JOINT COMMITTEES WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

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In the Matter of:                  )
                                   ) Docket Nos.
Informational Proceeding and       )
Preparation of the 2005 Integrated) 03-IEP-01
Energy Policy Report               ) 02-REN-1038
(Energy Report)                    )
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, SEPTEMBER 14, 2004

9:10 A.M.

Reported by:
Peter Petty
Contract No. 150-04-002

COMMISSIONERS PRESENT

John Geesman, Presiding Member

Jackalyne Pfannenstiel, Associate Member

ADVISORS PRESENT

Melissa Ann Jones

Chris Tooker

Darcie Houck

Timothy Tutt

STAFF PRESENT

George Simons

ALSO PRESENT

Ronald E. Davis
Davis Power Consultants

Kollin Patten
PowerWorld

David Olsen
Center for Energy Efficiency and Renewable Technologies

Anthony M. Visnesky, Jr.
Anthony Engineering Associates

Snuller K. Price
Energy and Environmental Economics, Inc.

Henry W. Zaininger
Zaininger Engineering Company, Inc.

Steven Kelly
Independent Energy Producers Association

Robert Sparks
California Independent System Operator

ALSO PRESENT

Mark J. Skowronski
Solargenix Energy

Daniel Frank
San Diego Gas and Electric Company
Sempra Energy

Chifong Thomas
Pacific Gas and Electric Company

Eric Toolson
Pinnacle Consulting

Richard E. Hammond
Optimal Technologies

I N D E X

P R O C E E D I N G S

9:10 a.m.

PRESIDING MEMBER GEESMAN: I'm John Geesman, the Commission's Presiding Member of its Renewables Committee. To my left is Commissioner Pfannenstiel, the Associate Member. To my right, Chris Tooker, one of my Advisors.

This is a joint workshop of the Commission's Renewables Committee and its Integrated Energy Policy Report Committee. We have initiated the process for our 2005 Integrated Energy Policy Report, and designated this particular topic, the integration of renewables into California's transmission grid, as a primary subject that we will return to, I think, again and again and again over the course of the 2005 process.

California is, I think, in its honeymoon stage with respect to renewables. And, frankly, it's a second marriage. We made a large commitment in the late 1970s and early 1980s to bringing renewables into our electricity supply mix. And achieved penetration levels in the 10 or 11 percent range.

We have recently initiated a new and

stronger commitment which is aimed at achieving a 20 percent penetration level by the year 2010.

The intermittent renewables, though, thus far have been a relatively small proportion of our electricity sales. The Commission's calculation on a statewide basis for the year 2003 suggests that wind contributed a little under 2 percent of our system sales.

Some utilities in some specific localities substantially greater than that. But on a statewide basis, our estimate is a little under 2 percent.

That number obviously is expected to go up between now and 2010. And the Commission's 2004 update of its Integrated Energy Policy Report, which we'll be releasing in draft in a couple of days, suggest that we embrace the Governor's goal for 2020 of a 33 percent renewables penetration target.

Again, it's not clear what contribution the intermittent sources will make, but they clearly will be larger than they are today. I would expect one of the principal challenges of California's utility system over the course of the next decade will be figuring out how to integrate these intermittent resources.

So we launched this process for the 2005 report. We've had an earlier workshop, earlier in the year, as part of the 2004 process. I believe we had a workshop that the staff conducted about a year ago on some of our initial studies. This will be one of what I suspect are many inquiries we conduct on this topic.

I'd encourage all of you to sign up for the long haul, to continue your contribution to our efforts to look at this question. I don't expect that we will reach any sweeping conclusions, either as a result of today's effort, or our sustained inquiry. This is, I think, a long-term engagement we need to conduct in order to have a pretty clear assessment of how to integrate these intermittent resources.

Commissioner Pfannenstiel, did you have anything to --

COMMISSIONER PFANNENSTIEL: No, thank you.

PRESIDING MEMBER GEESMAN: George, why don't you start us off then.

MR. SIMONS: Good morning; I'm George Simons; I'm the Program Manager for the PIER renewables area.

We do have a very full agenda. In the morning we're going to be talking about bulk transmission of renewables, and in the afternoon distributed generation.

I'll go ahead and start it off. I want to talk a little bit about an overview here, about what renewables transmission planning is.

First off, I think Commissioner Geesman was entirely right on target that this morning we're not going to reach any large conclusions. This is really an introduction to what we're doing in California with renewables transmission planning. Think of it more as a tool, and what we're going to be doing today is telling you about how we developed the tool, what the tool consists of, and some of the preliminary findings from it.

There's a number of components within this tool. We're looking both at the bulk transmission level, as well as the distributed generation level, because both of those play a role in how we will integrate renewables into California.

We're also going to be looking at what are the renewables outside of California, and what do we need to do with respect to transmission upgrades to bring those renewables in.

We're going to look at what's the cost of integrating renewables. We know that, for example, there are impacts and benefits on integrating renewables, whether that's on the price of regulation, load following or capacity.

And then we also want to look at the broader context and how does California fit into the western grid with respect to integration of renewables.

So if we're talking about components, again, we have a bulk system analysis that's largely been done, to date under our contracting process, with Davis Power Consultants.

We've looked at specific case studies down at the distributed generation level. We have three case studies so far. One is in the Chino Basin, by Hank Zaininger, who's going to talk this afternoon. Another in Bay Area communities by E-3; Snuller Price will talk about that.

And then Ron Davis is going to come back in an talk about how can we look at these distributed generation renewables on an aggregated basis, because, again, it would be nice to get some feeling, not just at the case study level, but statewide, what role do we see distributed generation renewables playing.

We also then want to begin to bring in the components dealing with renewables outside of the state. And some of that work has been done under what we call a programmatic contract with Hetch-Hetchy by a firm called Electronics.

We want to look at what are those integration costs; so, as we bring more and more renewables into the grid, we know that there's certain, again, impacts and benefits.

Then we want to put this in the context of California with the adjacent states, as well as California's part of the WECC.

Again, I mention that today is a full agenda. We do have a number of these components in this tool that we want to talk about. We couldn't fit them all into today's workshop. So today we're going to focus on the bulk and renewable DG evaluation tools, methods.

In late October, and going through November, and possibly into December, we'll bring up the rest of the components. Again, renewables imported into California; the cost of integrating renewables; and in fact, I believe there is a phase three report out on what I call phase 3A, which is focusing on the simplified methods of how you evaluate the cost of integrating renewables.

We'll then look at some multiple-year analyses. Again, in October we may have those in the same date, or we may have them in two separate dates. And then, again, we'll begin looking at integrating these into the larger western grid.

Today, again, we're going to focus on bulk renewables and DG renewable analysis. We want to, through this workshop, get a better understanding of how you look at what we've done with respect to the approach, the specific tools that we've been using, and the assumptions that we've made in developing these analyses. Because I think assumptions are very critical when you start talking about what's going to happen in the future with renewables.

And, again, as Commissioner Geesman indicated, we want to integrate this work into the 2005 IEPR.

There are copies of the agenda in the back. I think everybody has it. I won't belabor this, but again, morning will focus on bulk renewables. We'll switch in the afternoon to distributed generation renewables.

The purpose, again, is to allow evaluation of these options that we have with respect to integrating renewables, looking at what would be the best pathways for developing transmission.

Sometimes we look at transmission with respect to the entire grid, not just renewables. But, again, because of the Energy Action Plan, because of the goals with respect to developing renewables, we really have to balance those out with how we intend to develop renewables across the state.

We want these tools to be public domain tools. We want these to be available for planning purposes for the utilities and for project developers to have to allow them to better understand what are the options as they begin to talk about developing projects under the procurement process.

We also know that we have to establish a common set of assumptions and tools so that we have a common language when we're discussing these various options. And, again, looking at what are the pathways that utilities and project developers can go down.

We know in the past in developing some of this work that even the data sets, themselves, have had different nomenclatures, and that's been a source of confusion among the various parties.

And we think that this tool may, in fact, be a very valuable tool in assessing the least-cost/best-fit scenario for the RPS.

What we haven't covered under these evaluation tools so far is dispatch, there's static power flow models. There's been no production cost modeling done in these sets of evaluations. That's something that we anticipate adding.

Reactive power is not really considered under these preliminary analyses, but I think that's going to be a very important component for all of us to look at, to get a real sense of the benefits and the impacts.

And this is not a fully integrated set of renewables. So far, because of the length of time, because of the complexity of the analyses, we've put on blinders and we've only looked at wind or biomass or geothermal. And I think a very robust tool would integrate all of these. So as we begin looking at transmission corridors, we've looked at what's the full mix of renewables that could be developed.

I want to just provide a little bit of background to what is this tool contain. What we did, with subcontractors, is developed a forecast of what could happen to the electricity system in California, going out through 2017. And we specifically wanted to look at what we call hotspot. Whether those are congestion zones, or there's a capacity problem. And identify those.

Then using a geographical information system tool we laid out what we know about renewable resources in California, which is pretty extensive, actually, right now. We have a very good handle on wind, geothermal, biomass, solar resources in the state.

We plotted that out so in fact we could take the analysis about where the hotspot are, the magnitude of those hotspot, to see what are the renewables in the proximate area, and what kind of a fit is there.

In order to be able to look at the fit we needed to develop performance evaluations, okay. So what kind of generation performance do these different types of renewables have. What's their cost of generation. So, again, if we're looking at what's a good solution to that hot spot, we wanted to do that generically first. We didn't care whether or not, we weren't going to promote renewables; we wanted to see what the fit was.

So, we did essentially our own take on a best-fit/least-cost approach. And we did this, my group is actually an R&D group, and we did this because we wanted to look at if there needs to be performance or cost improvements in renewables, to go ahead and get out to a 2017 goal, or a 2020 goal, what types of activities did we have to get involved in in achieving those improved performances and costs.

I'm going to just very quickly go over the remaining slides here because Ron Davis is going to be presenting a lot of this material. But, again, this is the kind of analysis visually that we got out of these types of tools.

We can see that you get maps that show hotspot; those are the red areas, essentially. We projected those out. Again, these are very difficult to see, but the gist is that as you go out into the future, based on the assumptions you make, you get a pretty good visual depiction of what's going on in the state, spatially, as well as the magnitude of the problem.

And we took that all the way out to 2017. And again, we saw trends. We saw an increasing severity of the capacity and congestion problems. That's really not news. Our transmission folks could tell you that. What they couldn't tell you is what's the fit with renewables.

So we then mapped out the renewables. And, again, I mentioned that we have a lot of fairly recent and very comprehensive data on renewables in California.

As an example we have some resource maps. The resource maps, again, are very extensive. We have them down to a 200-by-200 meter resolution, which means that we have over a billion points of wind resource information predicted. We're getting it monitored. We're not going to monitor all billion points. But the fact is what we have is a very good map of the wind resources in California.

And so what we begin to look at is what we call the gross potential. So absolutely no limits on wind development versus a technical potential, which has the technical limits. What could you technically achieve with existing wind technologies. And compared those to get a sense of, okay, so where are the wind resources that we could harness in California.

We then went on to again look at performance type criteria. So we looked at historical performance. We looked at development trends put together by a number of different agencies and entities. We looked at cost. We, in fact, have developed public domain cost models that we will bring out to the public to use. We felt that was necessary because a lot of the cost models to date have been proprietary. And if people are going to work with these assumptions and these trends they need to have cost models that are in the public domain.

This gives you an idea of what we've began to look at. We projected out the costs and trends. And we see, in fact, that under certain assumptions you do get, you know, wind will continue to have a fairly robust or significant reduction in cost.

We mapped these resources out to, again, the hotspot in the maps; began to assess, based on the performance criteria, the fit between what would be a solution to that hot spot. So, again, here's a specific visual example of the type of work we did. I talked about those billion points. And each one of those little squares represents a wind information grid.

And so we drew radiuses around the hot spot to say, okay, within, for example, a ten-mile radius, how much wind of technical potential could you develop to go ahead and address that hot spot.

We came up with some very interesting preliminary results. We looked at this is the potential in both what we call low-speed and high-speed wind potentials. And you begin to see that HWS is high wind speed, LWS is low wind speed. You can see very large potentials, okay. These are, again, technical potentials, not economic at this point in time.

We again looked at these going out to 2010. Looked at the capacities of developing these now, based on the cost, performance; and came up with some, this is what you could economically develop. And, again, Ron will talk a little bit about how we actually developed those things. Again, projected it out past 2010 to 2017.

We added in the transmission costs. One of the things that Ron's group did is they looked at what would be the incremental transmission upgrades to develop the wind that we saw was economically viable. And so now what we have here is -- and this is not just, you know, Ron saying, okay, well, let's just throw this in here -- Ron went to great pains to go ahead and say, if I put this in here, what impact does it have on the grid. So, there's actually a fair amount, there's a very exhaustive amount of analysis that lies behind these preliminary results.

Then we began to combine these projections to look at so what are we really talking about overall in terms of a 2010 and 2017 development prospect.

We went down into some detail. So, for example, here's Solano. So you can specifically go on and look at what are the specific transmission lines that we're talking about. What needs to be upgraded. What substation transmission line needs an upgrade. And what are those upgrades. And, again, down in the Tehachapi area, we've looked at it.

I'm going to stop here, because, again, this is the level of detail that Ron's going to get into.

One of the things I do want to mention is that all of the analyses that we have on this stuff we are going to make available to folks. We want to have the opportunity for folks to really look at this, look at our assumptions, look at the power flow analyses that were done, look at the cost projections, and to feed back to us, no, that's all hogwash, you're off by this factor; or you're right on target; or maybe some mix of those.

Again, what we want to develop is an approach that we feel comfortable with, an approach that the industry looks at and gets some value from.

And with that I'm going to go ahead and bring Ron Davis up to the podium.

MR. DAVIS: Good morning. We're going to talk about what we've done as far as looking at renewables and how they can work to help on improving transmission grid reliability.

George was nice enough to cover half of my slides so my presentation will be really neat and short this morning. I really appreciate that.

One of the things I want to go over and talk about is, you know, under the PIER program, of course, George is our area lead, and Prab Sethi was our project manager for this work. The consultants here today, that are with me today is, of course, myself, Davis Power Consultants; Kollin Patten from PowerWorld Corporation, and that's the power flow model that we're using; Tony Visnesky from Anthony Engineering is also a part of the project here. And so I brought him out here today, so if you ask me any hard questions I'm just going to give them to him and then I don't have to answer them.

So anyplace that I have in here that refer to DPC, that is the entire team that worked on this project.

The agenda for the morning is I'm going to go over the introduction; going to look at the objectives; the organization; the model that we picked to do the work; and why we picked PowerWorld.

And then I'm going to talk about applications. And what we're going to do is we're going to start out talking about results. So instead of getting into the methodology and some of the terms and other things, we're going to get into some of the results to show you what we've been able to come up with. And we're going to concentrate on geothermal and wind.

Then we're going to look at what other applications, what we've developed and worked. We're going to look -- in looking at, for example, aging power plants; going to look at conventional; going to look at transmission expansion.

The last one, the policy using penetration curves, actually is going to be in a later topic.

Now, I'm going to have Kollin Patten come up and he's going to talk about the model and how we determined what methodology and what process we used to find these hotspot, as we call these. And then how we determine the value or where we should be putting the generation. And so he's going to talk about the logic within the model. And then I'll come back up and talk about the conclusions.

The purpose of the strategic value analysis was to, as George said, talk about performance and costs and where we can locate renewables. So, in fact, instead of just looking at putting renewables anywhere in the system, are there places that would be more of a benefit to the system and improving transmission grid reliability.

We initially -- this a typo -- we initially only went out to 2007. It wasn't until it was expanded to look at the 20 percent penetration that we went out to 2017. So our initial case was to look at 2003, '5 and '7. And then when we started looking at the RPS project and looking at extending it out to look at the 20 percent, then I added 2010 and 2017.

The approach we took was to try to define the links between electricity needs and where renewables can be located. And so part of this whole process is to look at the electricity system, look at the transmission, look at the environment, and look at public benefits and look at local economies.

I think George kind of went over this as to the five steps that we used to first identify where our hotspot were, our potential transmission problems are. And then to identify how to map these, and then how to look at what kind of megawatts to get to be installed to improve transmission reliability. So I'm not going to go into this one too much more.

So, basically on project overview, in order to develop an energy policy we first need to look at the electric grid reliability, and that's the power flow model to look at the low flows.

Then develop the characteristics of renewable resources. But in doing so we also have to look at conventional, we have to look at gas-fired generation and also transmission, because we have to compare those to putting in renewables.

And then we have to look at the public benefits of different alternatives and different types of renewables.

And then tie this all to GIS mapping. And we think this is really the key to what we've developed is the ability to be able to map this into California.

The model coming up with the methodology for doing this is first to come up and get the database. And so we had to work with the utilities and other areas and develop a good database that is representative of California.

And then the part down at the bottom under DPC is once we have a merged case of the entire State of California, how do we go through a process that becomes automated to find the hotspot to determine where we should be putting them; and then look at the megawatt solutions; and then how do we tie this to a GIS overlay to be able to look at the value of these.

So there's three basic models that we looked at for the development of what we've done here. The first one, of course, the key is the power flow modeling. And we had to have the economic models, and then be able to tie into the GIS mapping capability.

We have the California Department of Forestry was really responsible for the GIS mapping and tying our busses and everything together into doing the mapping. We did not want to have it as part of the PowerWorld package or what we were developing on the power flow, so we worked closely with CDF to have them do the mapping and to do our work on tying this all together.

We simulated over 6000 contingency analyses in the State of California. So we ran N-1, the standard NERC N-1 standards. And so when we mapped out the entire State of California we ended up running over 6000 cases. So the process was to run all those cases; determine the potential location for renewables; look at how much megawatts injection that we would put in at each of the busses that were there. And then overlay the renewables to find out where we would be putting them in.

So the first thing we had to do was find the model that we wanted to use to be able to do this, and we looked around and we looked at a model that would be interactive, portable, easy to use and expandable. And, in fact, as I said before, we were able to program all this logic of finding the hotspot into the PowerWorld model.

Made it a little easier in determining to pick PowerWorld since my company uses it for its work. And the Commission also has it inhouse. And so it's widely used throughout, so it was very easy to come to picking the model because it's versatile and well recognized.

The model can handle power flow analysis contingency. We can also look at tying into the GIS overlays and making a nice mapping system.

It has other capabilities that we may want to use later on so you can look at voltage stability; you can look at optimal power flow. One of the things we may eventually want to look at is when we redispatch the system as we're installing some of these renewables, and maybe if we start looking at congestion zones, we may want to eventually look at looking at redispatching the system on an optimal power flow and looking at the capability and what happens on the system. We did not do that here due to the time constraints and our goal was to get some sample of what we'd be doing on the system.

This just says, you know, it's widely used throughout the United States and it's used by large and a lot of different sized companies.

One of the things we really liked and really wanted integrated into the model was the fact that we have -- that most of the 69 kV, the 115s, the 230 and the 500 kV transmission lines modeled in the data set, we've not only modeled California, but we've modeled the whole WECC region because we've got to look at inter- and intra-power flows. So we've actually modeled the whole WECC region.

And so since we have every buss and it has an XY coordinates to know where they're located, one of the things is within the model you can have this map appear and you can be looking at areas, and then what you can do is you can start and zoom in on areas.

So if I have a particular area that I want to look at, if I'm Southern California Edison or San Diego or I'm a developer and I want to look at a particular area, I can now zoom in on that area and do a power flow. And each one of these green arrows is a different simulation as it's doing its contingency analysis.

So you can see how the power is flowing. You can look at where everything is located. And you're going to be able to see how the system is integrated. So, from one model, one database, you can look at the entire state and be able to zoom in on areas.

If I was to look at a simplified power flow simulation, in this example we can see how the power is flowing between these different busses in this case. One of the nice things that comes about, if we start and look at the contingency analysis and I take this line out right here, then we can see that we have overloads that occur on the system. And we can look at a loading on the system as it's occurring.

This is really nice in doing contingency analyses because now we can be able to easily show on a display, and it's easy for people to understand where the relationship between overloads and outages occur on the system.

And as we're saying, we've done, for this outage on here, we're running about 6000 of these cases and doing one simulation.

Once we have the power flows up and running, and we have the analysis, now the next thing is do the economic modeling. And here we use standard pricing for transmission lines by voltage type and also substations. So we didn't go in and we didn't go out and look physically at each one of the busses where we're installing anything. We didn't go out and look -- river crossings, but we did some generic costs that we obtained from EPRI and some other areas in order to come up with some generic costs that we used.

So what we end up with as we're going

through this, is we end up with a levelized cost of energy. So we've kind of come up with a way of calculating and comparing these.

So we calculate the cost of the generation and we look at the capital costs and we convert it to a levelized cost of energy. And then we add to it the transmission costs. So now we come up with a total levelized cost of energy.

This allows us to compare different sites together by an economic cost. And now we're going to be able to look at its value to the transmission system; and then we can also now look at the cost between the different alternatives.

We haven't, on this part, talked and done anything on public benefits, but the other thing you can do is now on evaluating different types of resources, begin to look at public benefits. Does one technology help on reducing pollution, improving on reducing wildfire exposure, increasing employment, safety. By doing GIS overlays and looking at different things, we can now begin to overlay different components and look at what resources would provide the best benefit in the area.

What I want to do now is jump over to

some examples of what we actually went through. And so, as I said before, we looked at geothermal and wind. And I'm going to go through just a couple examples and show you what we did.

George had already talked about the mapping of the renewables, that we went out and be able to get updated information on wind and geothermal locations.

So the idea was to, in looking at a power flow and looking at transmission, one of the things we wanted to do, if we had a hot spot or problem areas, one of the things we wanted to do is look at where the renewables were at. How much renewables could be installed on the existing transmission system to reduce the overload.

So instead of going in and looking at building transmission right-of-way, we wanted to look at what could be installed on the existing system.

So in doing this analysis as transmission planners and people who are doing resource planning and transmission planning would know, there was a lot of iterations run. And we did a lot of analysis in a lot of different cases to look at the amount of megawatts, where it could be connected, what different points if you had options of connecting it to several different points where would you connect to provide the greatest value.

So there was a lot of iterations, a lot of cases run for each of the examples we were doing. And we only selected a few because of the time it takes to perform the analysis.

If we needed a new transmission line then we looked at where it should be built, what is the size and what voltage. And run iterations again on where the new line should be, the size, the calculation and how many megawatts we should be installing.

Once we have that now we can look at the length of the transmission lines and the substation and the amount of generation or renewables we're going to put in. And then we can make up some timelines. And then we can separate resources into installation periods.

So maybe there's something we can install in the next three years, the next nine years and then over ten years if there's a major transmission line that has to be built. And then we can do some prioritization of looking at where we should be putting these in.

As George had said, the first thing was to try to come up with the gross technical potential, and then try to look at some economic potential. And so if we looked at the whole state and we looked at all the potential wind sites, there would be really too much to study for what we're trying to do right now.

So we took from the gross potential down to a technical potential that we could deal with. And then from there we picked selected sites that we wanted to study and we wanted to look at.

I think George has already talked about this, that we wanted to identify where the hotspot were and then look at the megawatt solutions and then to map these out.

Now, there's going to be some terms I'm going to talk about here, and mention, but they're not going to be defined and really explained until Kollin comes up. And of the things is the way the transmission loading relief.

Basically within the model we developed a methodology that Kollin's going to talk about where we look at how much resources, how many megawatts of resource would have to be installed at each buss to relieve the overload. And then we weight those by a methodology we come up with that looks at the voltage, the amount of overloads and how many times it occurs. So I'm not going to get into that here.

The other element that I'm going to be talking about is what we call aggregated megawatt contingency overload. And basically what we do is we do a summation of all the contingency overloads that's in the state and we come up with a value. And that's an index that we use so that we can compare the value of different alternatives as to its ability to reduce contingency overloads. Here, again, Kollin's going to talk about that more in detail.

As George has said, one of the problems and one of the things we had to look at was if we have a transmission line and we know we have a hot spot in an area by GIS mapping we can now look to see what wind spouts are located within that hot spot or close to it. And within the GIS mapping we can set up different circulars that we want to look at. We can look at a ten-mile radius, a five-mile radius. And so we can be able to begin looking, if I have a hot spot and I have some wind potential and I can draw a circle around it, then I can look at how many megawatts I can install within that area to look at the reducing the hot spot in the area.

This is really messy and we've shown it before, but all these red and different shaded triangles are areas that we have for hotspot in 2010. Now, some of you that are transmission planners are going to say, well, we wouldn't have that many hotspot by 2010.

Well, we didn't do any solutions. We didn't put any new generation. We didn't put any new transmission lines in. We wanted to find out where the hotspot are. So if we're starting from scratch where we would look to put new generation in there.

But now this has really got too many things to be studying. So what we did then is pick certain sites to study. And we picked these different sites to go through and to test our analysis and our methodology. And we tried to pick areas in different locations within the state, different megawatt areas and at different voltages.

We then looked at the amount of -- here, again, this was the high/low speeds where we looked at where we can be putting them in and what the megawatts potential was going to be in the area.

So now once we have the wind technical potential then we begin to look at the GIS mapping. We begin to overlay our transmission hotspots. Then we calculate a benefit ratio. And what we're doing is calculating a benefit of one alternative versus another.

Now, for wind we've come up with a new term. Effective transmission wind capacity. The amount of generation that could be exported over the transmission grid at the summer peak, which we're simulating in here, which is the summer peak period.

Now, I'm not saying this is how much is connected; I'm not saying this is what would be installed on the system. I'm saying this is how much wind power could be exported or flow over the transmission system. We're going to rely on the experts, which are the wind developers and the transmission and the utilities to come back and say if I wanted 100 megawatts of effective wind transmission, wind capacity, how much would I have to actually connect and build on the site.

I didn't want to get into that discussion as to that because we're not really getting into that much detail. So we're just saying, this is the amount of capacity that could flow over the line.

If I look at my 2010 hotspot, the bright red areas are areas that would be the primary areas where we would look at trying to solve first. These are areas that will have the highest concentration of transmission overloads.

Not only can it be overloads, it can also be voltage. We can also look at low voltage on this, also. In fact, in the San Diego case I'm going to show you we actually looked at things on some low voltage.

The yellow areas are areas that are secondary that we would look at to install generation. These are also really good areas that we'd want to look at putting in either, in this case we're looking at renewables, but we could also look at conventional or even transmission improvements.

The blue areas are areas that says these may be good areas, but we recognize we have to do some transmission additions and transmission upgrades before we can even think about exporting from those. So we're not saying you shouldn't develop there, but they are areas where we're saying you need to do some things right away on the transmission system in order to get anything out.

We looked at Solano County wind site, and we had a technical potential of 275 megawatts. We assumed it was located in the southeast corner of the county, and we assumed that in doing probably 10 or 12 cases, we picked that we would connect to the high wind tap. And wherever the wind site is being built in that area there would be a new substation, and it would connect to this tap. The tap is connected to the VacaDixon/ Contra Costa substation by a 230 line.

We come up with the amount of megawatts that we can install at that substation and that transmission line without causing an overload. And basically what we're looking at is on this area in here we're looking at where we can install some generation and tie into these two lines. And a look at how much we can install on the system without creating an overload.

We came up with that we could actually install 165 megawatts of wind generation, or have 125 megawatts of power flow from wind on the transmission line without causing a major overload. However, its impact ratio for installing 165 only adds a value of 111 megawatts to actually reducing the transmission overload. So it actually has less than a one-to-one benefit of installing it.

So although it's a good area to install it, its benefit is, if you install -- or we have a power flow of 165 megawatts, its benefit to reducing the transmission grid reliability is only 111 megawatts. So it's less than one.

We came up with this solution; we looked at this run; and then we were able to go back and look at the PG&E renewable concept plan. And they installed, and showed installing and having 175 megawatts on the line. Anything above this line, as we were doing simulations, that you go above then we would have to build a second 230 line from Vacaville -- VacaDixon to Contra Costa.

We didn't get into installing that second line, and we stopped here. And we came up with 165 megawatts, and in PG&E's concept plan they come up with 175. So we were pretty comfortable with what our results showed.

This is going to be hard to see --

MR. KELLY: I'm sorry, but I think this is important for the rest of your presentation. Would you go through that, how you calculated that ratio again?

MR. DAVIS: Yeah.

MR. KELLY: The second bullet is the part that I'm still a little confused on.

MR. DAVIS: We're going to get into the impact ratio a little bit later in Kollin's presentation, but basically what we do is we do a contingency analysis of the entire state. And then we calculate what we call an aggregated megawatt contingency overload where we sum all the overloads that occur in the state and we come up with a value that's an index.

And let's say for discussion purposes, and Kollin will get into it, that my index and my summation for the entire year is 7000 megawatts. That's not how many megawatts you have to install to get to a perfect reliability system. But it's the summation of all the contingency overloads that occur within the simulation, of all 6000 iterations. We come up with a value that says the summation of all those adds up to a value.

Now, as I install generation, renewables, conventional or transmission line, that impact or that summation will decrease or increase depending upon if we're putting things in that's a value to the system or a detriment to the system.

So, let's say if I'm at a 7000 megawatt contingency overload and I add 165 megawatts of renewable generation at this site, I actually reduce my 7000 down by 111 megawatts. So that's its value as to its improving reliability to the system. So it creates a value to the system.

Now what we're saying then is this location, although it has a positive benefit to the system, it doesn't have a big benefit to the system. It's less than one-to-one ratio of installing those.

So all we're doing is we're trying to create an index of summing the contingency overloads over the entire state so no matter if we're studying PG&E, San Diego, Edison, Imperial, Redding, Santa Clara, we have a way of valuing those on a common basis to look at their value to improving the transmission reliability of the system in general.

And on your black-and-white copies this is going to be a little hard to see, but what I want to talk about is the site we were looking at was right in here in Solano County, and that's a light yellow area.

And over on the other map you see, it's hard to see, but it becomes almost white, so the yellow almost all goes away. And I leave it as a big map. I could have exploded this up and showed you in more detail, but the key point is we can study this down in fine detail, and we can be able to compare resources over the entire state and look at their impacts.

Now, I picked an area that was a light yellow because it was one of the spots that had existing wind; it was a place that we can install some more wind; but I wanted to be able to show you that we can actually go down into small details of putting in only 165 megawatts, but be able to still calculate its value in the whole system, and be able to look at it and its value to improving reliability. And that we can map these out and be able to compare these and actually see changes in time as on the mapping, be able to compare.

Now we picked this place down in southern California that we wanted to do the analysis, and although we had these different sites, we had L.A., San Bernardino, San Diego and Riverside, for this one I'm actually going to pick Riverside, do some analysis in looking at the Riverside area.

And the Riverside area, as we're looking on here, has the capability of about, from the technical potential that was created by the Commission and CDF, we looked at about 1400 megawatts of potential for wind development in the area.

We picked these substations in order to install the new generation in Riverside County. Now, we didn't go down and look and see if there's capability to install additional; we didn't see if these exact new potential matches these, but we installed them on the substations and assumed we would distribute the megawatts the best we could over the entire system, knowing that they're going to go out over the same transmission grid system. So regardless of whether there's a new substation that's created in the area, or we actually expand the existing, the objective was to say if it goes out over the same transmission grid how much can we install without creating a new problem.

As we said, there was a total of 1416 megawatts of high wind technical potential. And we assumed it was located in the northwest corner of the county.

We actually came up with a 787 megawatts of effective transmission wind capacity that we could put on the existing transmission system without creating an overload.

So we did several iterations and we looked at a lot of different megawatts and we come up with about 787. If we were to put this 787 megawatts onto the existing transmission system, the impact benefit to reducing transmission -- to improving transmission reliability is equivalent to installing 1000 megawatts. So for every megawatt of wind that we install we got a 1.4 megawatt benefit.

So that we did not have to -- but now that we have the wind on the major transmission one of the things that we realized was we're now competing with bringing power in from Arizona, other development in Imperial and in other areas.

And, in fact, it was very interesting results, and it took us some time to think about this. On the before case we have all these red and yellow areas. But now that we installed this 800 megawatts, we now change a lot of these red areas to blue.

And so remember when I said before that the blue areas, they're not bad areas but we have to do more transmission upgrades before you can do anything with it. And after thinking about this for awhile and looking at what we really come up to say, by putting this 800 megawatts of wind on the system in Riverside we've actually loaded the transmission system up to 500, to the point that we can't do any more development in the area until we do more upgrades to the transmission system.

And so if we want to do any development in Imperial, we want to bring any more power in from Arizona, or into other areas now we need to do more improvements into the system.

So this is one of the really nice benefits that we didn't really realize was going to come out of this. But it allows you, on the mapping system, to be able to look at the impacts into other areas.

And so by installing generation in a local area that we may do some improvements, but do we hinder other areas, or do we create problems in other areas.

So this would indicate that before we do any more development out there we need to look at how now do we strengthen the major transmission system that's out there, and to be able to bring more power in.

As I get into looking at the geothermal into the Imperial you'll see by installing another transmission system in there it will change the perspective again.

So, as I said, the Riverside site shows a benefit to the system, but you also see where it places a stress on other places on the transmission. And that we need to look at more upgrades and more improvements in the area if we're going to do any expansion into those areas.

I'm not going to look at San Diego County, and I looked at a site in San Diego County that had a potential of 756 megawatts of wind. The nearest buss that was located was on a 69 - I think it was 69 or 60 kV, can't remember if San

Diego does their voltage here, so it may be 60 kV.

And we really looked at this in two points of analysis. The first one we did is can we install anything on the existing subtransmission system. And how much can we install on that. And then if we have to go out and build a new transmission line to get this power out, where would we build it.

One of the things we looked at was okay, if we looked at the subtransmission system how much could we install on the existing 60 kV, 69 kV system. We actually found that putting any wind capacity on the line did create overloads. The lines are long; they're small conductors; and so putting in wind generation on the lower voltage did create a problem. And actually the impact ratio increased. It was a positive 1.13, which says it's actually makes the transmission reliability worse.

However, it improved the voltage. And what we discovered when we were simulating the summer peak case that the voltage increased significantly and added a lot of benefit. So one of the things you can look at is not only its value as far as improving the grid reliability, but you can also look at it as improving voltage.

If we wanted to install anything above that initial 30 megawatts we had to go and build a new 138 kV line. And we had to -- we looked at the system and we decided to go to the Los Coches substation.

Now what was interesting on this one here then, is once we installed this new 138 kV line, and then we started to look at the power flows, we were overloading other lines. So installing a wind generator and then wind site and then building a new transmission line actually created about five additional overloads on the system. So in order to get the power out of Los Coches we had to reconductor other subtransmission lines and other 138 kV lines.

So the model allows us to look at this detail of if we do anything what impact does it have on the surrounding area. So we were able to go through and actually look at what would happen and then factor in those costs.

If we installed a full 90 megawatts of wind, 30 megawatts on the 69 and 60 on the 138, we ended up with a composite benefit ratio of 1.6 to 1. So really the area is really a good site for putting in wind. But it creates other problems and doing additional upgrades and additional reconductoring.

If we were to look at the map here again we can see that it does improve the areas both in some and over in Imperial area, and along the San Diego area, so it does provide a benefit to the system by looking at putting in generation in those areas.

Here, again, we went through and we did the analysis and did a lot of the simulations. And then we ended up with, as we were looking at this, that San Diego, in looking at their concept plan, actually had something very similar to what we had come up with for an answer. They had come up with about 30 megawatts on for their subtransmission system. And they come up with a maximum of 195 megawatts that could be installed on their 138 kV line.

We did not go to the max that we were looking at. We stopped at 60. But, I believe in their case they were installing multiple 138 kV lines and getting the power out.

What happens after that, if we go above the 195, or the megawatts of installed, then we've got to look at getting onto the 500 kV system, or building a bigger one in order to get the remaining power out.

So one of the things that we looked at in conclusion with this was if we wanted to get some wind development started you could go and start developing on the subtransmission system while you're building 138 kV and continuing to build out the other areas.

So, the model allows us to look in some more detail as to what can be done and how you can phase in the value of installing renewables over a period of time.

If I look at the site that we looked at here, we did the six sites that we looked at. And these are the impact ratios. Now, it's interesting, you'll notice that Kern County actually is an area that has a positive ratio which says it doesn't add any value to the system. But I'm going to clarify that a little bit.

What we did on that is we didn't study the 2000 megawatts that was being proposed in that area. There has been a lot of work being done that Edison had done, and also there is a group that's working on studying that area.

So, what we looked at was only installing a minimum amount of generation initially in that area. And we said how much could we really add to the existing transmission system. And what would be its value. And so how much can we really put on the system without doing any upgrades. So we really didn't get into studying the extensive 500 kV, 230 kV that they were proposing in the area.

But we looked at the other counties. And as you notice, San Bernardino County has the highest impact ratio which comes out to show the biggest benefit. San Diego has a positive. And Solano County was the one that we had picked to show before, and it has the smallest benefit on these.

Now, once we know the benefit ratios we can now compare the sites as to which one provides the best value. Now we can begin to look at its levelized cost of energy for the different wind sites.

Here, again, this Imperial is a typo on my part. That should be Riverside. When I was making the slide up -- that should actually say Riverside instead of Imperial.

And so now you can see that the levelized cost of energy for installing at these different sites. So now you can begin by looking at the different sites, be able to weight them by their levelized cost of energy and their benefit to improving the transmission grid reliability.

If I was to look at the wind potential versus what we actually showed on the system, these counties had a total of 4979 megawatts. We only showed studying 1589. The biggest one was L.A./Kern County, which has a technical potential of 2000. But we stopped at 300 because of our time constraint and the fact that we wanted to get through and get some results out. We then studied the whole Tehachapi area, but we left it for analysis at a later date.

But you can see the comparison between what the technical potential was and how much could be installed at the summer peak. Now, what's missing on this is to be able to do other time periods within the power flow. And one of our goals was to begin looking at a spring period and a winter period and be able to look at how these benefits and how these things occur and change over time and in different seasons. So, does wind have more of a value in the spring or in the winter. And to be able to look at these in a little more detail.

You had seen this before as we had shown on here that these were the sites that we thought could be installed by 2010; that we could be putting in some generation.

This was the capacity and the costs. So now you can begin to look at where the different locations are. You can look at their costs to be able to see what would make sense to install, and concentrate first on developing some wind generation.

These are the sites that we picked and said they might be viable by 2017. And this was their amount of megawatts, and looking at those. And then this would be wind capacity and costs associated with developing these. And George had already shown you these before. And this was the combined 2010 and 2017 development.

So now we're able to go through and evaluate what the potential is, what the transmission impacts are, where these are at. And now we can develop some timelines in looking at which ones you would look at first; which one has the greatest value; and be able to compare these.

I'm going to switch over and talk about our geothermal example that we went through and did. And if I'm looking at this as my existing geothermal development, these are locations where we currently have geothermal. And now what I want to look at is my geothermal technical potential.

And so the areas on here are areas that we feel from the CEC doing some analysis where some additional geothermal can be developed. And we have areas up in here, in the northeast corner of PacCorp -- Pacific Corp's area that has potential. The Geysers, we came up with there might be some other development in there. Mono Valley, Long Valley over in this area. And then we get down into the main area which is going to be the Imperial area for development of geothermal.

So the statewide technical potential came out to be over 3800 megawatts. If I was to overlay my mapping of transmission hotspot to where the geothermal areas are, you will see that we do have some hotspot areas and some development areas where the Imperial is. And we have a lot up around the Geysers area.

But up in here, looking at Glass Mountain, Lake City and Surprise Valley that's really in the PacCorp area, and we don't really did any modeling in that area. But we'll be able to do overlays, and now we can start and look and see what geothermal sites we want to look at first to begin to develop if we were going to do any expansion.

Here again we followed the same process that we had done before in looking at determining potential, looking at the mapping, and then looking at the hotspot and trying to find the solution.

If I was to look at my 2010 hot spot basecase map again, we can now look at where the hotspot are located at. And we have Imperial Valley, and then we also have up around the Geysers that we have locations to put in geothermal.

In PG&E's area, these are the ones that we came to want to look at, to study. And these are the counties they're at, and where they're kind of located. PacCorp had Lake City and Medicine Lake.

And Edison, we had some areas in

Edison's that we wanted to look at, that we had picked to study.

In Imperial's area these were the locations that we had selected for potential geothermal development. And these were the areas, so that if we looked at -- sorry, going back to where the IOU geothermal sites were, there was about 1200 megawatts of technical potential. And the sites that we had picked, there was about 1600 megawatts down in the Imperial area.

So then what we did is we picked these areas to do further analysis and study. We first went up to the Geysers at Lake County. It was difficult to determine from the mapping of exactly where the new geothermal development would be, but we looked at connecting it to the Eagle Rock substation.

When we did that we discovered that we did create transmission overloads. Although this is a good spot to put in generation, or put in new generation, but we required that right away it created a transmission overload on the existing system. So after some analysis and looking at load flows we determined that we needed some new 230 transmission lines.

Installing 152 megawatts of geothermal at the site has a benefit of 442 megawatts on the system, or an impact ratio of almost three to one. So putting in a baseload geothermal plant at this site really improves the transmission reliability of the area.

And if I'm looking at this again, here again this is in a small area, but we're looking at the before case up in this area, and the after case over in this area. And it's really small and hard to see, because here, again, we're evaluating it on a total system, but we're looking at a small concentrated area for transmission improvements.

So what we wanted to show is we could even, here again, same with wind and geothermal, we can study smaller increments of additional generation being installed and see its benefit on the system.

We next looked at the Geysers in Sonoma County and we said 300 megawatts located there. And we assumed it was located in the south end of the existing geothermal fields. The first one was on the north end; and this one is located on the south end.

Here again when we tried to install any

generation we immediately caused overloads on the transmission system, which required additional 230 upgrades, additional substation and transformers, and multiple transmission lines. And we're still looking at this area up in here that we're looking at.

Installing 300 megawatts also has a benefit of improving the system of 2.23 to 1. So installing 300 megawatts has a benefit of reducing the transmission contingency overload by 670 megawatts.

One of the things we didn't include here but we looked at, was if you're going to develop those sites, then we really needed to look at what we have to do to tie these two together to improve the system even more. So if you're going to develop both sites, then if you did a little more transmission expansion then you can get the power out and provide more benefit for more areas.

Here again it's hard to see, but we're looking at these areas right in here and the change that's occurring on those.

And this is a bigger area to show that we were looking at the north end for the Geysers at Sulfur Bank, and the lower end down around here for the expansion down through here.

Now we went over to Salton Sea and we began to look at the higher penetrations. And we picked Salton Sea development; had a technical potential of over 1000 megawatts. And in order to get anything out of the Salton Sea we had to look at expanding the 500 kV system. So we looked at adding another Palo Verde line, Devers, and going over and building a whole new 500 kV line.

So in order to get the 1000 megawatts out we had -- that before. In order if we installed the whole 1000 megawatts of geothermal at that site, we only got a benefit of about 715 megawatts to the system, or a ratio of less than one.

We still think this is a good project to develop even though the site has got a less than a one-to-one benefit, because the amount of geothermal that's being developed there of baseload renewables, and also by building the 500 kV line we're allowing more imports and more capability to be coming in from Arizona, and be able to utilize the line -- utilize the line better.

Now, the impact ratio shows a lot more,

building the 1000 megawatts down in Imperial we've eliminated all the areas in the red area down in here, and we're studying 2017. So in this case, because of the 500 kV line and the fact that it's going to take longer to develop, we model 2017 in this case, and now you can see by installing 1000 megawatts out in Imperial it has a big improvement to the system in southern California.

Now, here again, you've got to remember that there's a lot of red areas in the southern California area because we are not adding any generation but we're letting load growth continue to go, and we're stressing the existing transmission system.

This is what I said before, that it provides more benefit to the system; and if it's designed properly then we can tie into other development.

If you remember the Riverside wind and the fact that it created a problem in the area, now if we develop geothermal at the Imperial area, now we can tie into the wind development in Riverside and be able to add more generation and more types of renewables over the new system.

These are the sites that we looked at

down in the Imperial area. And so we looked at all these individually. And we haven't gone through and looked at integrated as to -- but we wanted to look at them individually as to what their costs would be, what their benefit would be.

So we studied each one individually and we did not look at combining all these into one yet. That is something we'd still like to do and develop it. Right now we did each site as an individual site to see which order and which priority we would be trying to build them.

If I looked at a comparison of all the geothermal impact ratios for the ones that we studied, you'll notice that there are some that are positive, Coso, Hot Spring and Randsburg. And these were over in the Mono/Long Lake area. And that really requires a lot of transmission and a lot of upgrades in the area. And it was really difficult to get any benefit unless you do a lot more expansion in that area.

Superstition location actually came out to be a very good spot; had a high impact benefit ratio of 15 to 1. But that's only 42 megawatts. So it's a very small geothermal site. We didn't get into would we actually build that, or do anything of one site for 42 megawatts. But it's at a location that provides a really major improvement to the area.

But this allows you now to come in and evaluate the different locations. And we can see that the geothermal in Imperial Valley has a better ratio and better value than the ones in PG&E's area and to the other areas.

We didn't study this last one on here at all because it was a location that ended up not having any -- it was a good area for development, but it didn't have any transmission that would get out of there. And we would have to create a lot of development for 6 or 8 megawatts. I think it was a site that had very low potential. So we looked at that and eliminated it, didn't include it.

If I was to look at my levelized cost of energy we can now compare their cost to develop these sites, including looking at the generation costs, capital costs of building the geothermal, plus the transmission lines.

You'll see some of these are blank because they were either positive or ones we didn't study, so we didn't include them in our analysis.

So those are the sites that we had picked to kind of show and demonstrate how we could use this to value where we could look at geothermal and wind sites. What we'd like to do is be able to tie this over to looking at solar and also biomass. And being able to look at landfill, look at waste treatment, look at commercial solar, residential solar, central solar locations and be able to expand this into other areas. And then begin to integrate these different resources together.

We've been talking about renewable because that was what we were doing with George, looking at renewable resources. But we also have to look at what other areas can this model be used in this field to compare. And so we feel that it has real good -- fits into doing transmission, transmission planning, of adding to the transmission grid, and also to installing generation, conventional.

So if you can think that we have our hotspot mapped out, and you overlay gas lines and you look at major and minor gas lines, and you tie those to where the hotspot are, now you can begin to see where should I be putting in some conventional generation that might also have some benefit, because it's close to a hot spot and close to a transmission line.

One of the things I just quickly, and I didn't come up with a solution, but I know there's been a lot of talk about these aging power plants. And so what we did in a quick simulation is we actually took Pittsburg out, and we said what would happen if Pittsburg was actually retired.

And as you can see, when we did, I think this is 2010, I believe, that taking out, I think what is it, about 1000 megawatts that Pittsburg is, it creates a 6000 megawatt increase in the transmission. It adds to the problems that the transmission contingency overload. So about 6000 megawatts. So taking out the 1000 actually makes the transmission reliability of the system worse, which would be what's expected.

But if I was to look at a mapping of it, and this was the area before I took Pittsburg out, and now I go over and I take Pittsburg out, and I can see the increase in the red areas because of the fact that I'm losing the 1000 megawatts of Pittsburg that's in there.

Now, one of the things we can begin looking at is, is there any renewables in the area that could add a benefit to the system. And the other one would be really interesting, is since Pittsburg was first developed, as the load center has changed significantly, that now you would look at maybe locating at a different point and maybe have generation installed somewhere differently to provide a bigger benefit to the system.

So we feel this has a benefit in expanding and looking into other areas to be analyzed, taking out, losing power plants, or adding transmission lines and looking at their benefits.

So one of the things that we were looking at was its ability to be used for transmission siting. If you have several alternatives that can be built for a particular transmission line, we can now run this analysis and compare their benefit to improving the transmission reliability, and have a way of comparing them on an equal basis.

Because we're studying these on a transmission system basis and looking at the entire state, it allows us to look at multiple scenarios in different areas. Because we've tied the system together and looking at the entire state, if we're looking at building a major transmission line, it will have an impact to the other utilities, also.

So building the Palo Verde/Devers line and bringing more power over there, how much benefit does that have to reducing congestion in other areas and providing benefit up into the northern California area.

And in looking at transmission siting, how does renewables play into this. If I have to build a new transmission line and I have renewable development in certain areas, can the transmission line be routed such that we can take advantage of renewable technologies as we're developing it.

That's what I covered so far on the areas of our examples for how we can use this model to evaluate renewable resources and their benefit to the system.

I'm now going to have Kollin come up and he's going to talk about how we developed this methodology, and how it means and what these terms and conditions I've been throwing around, what these terms mean. So he's going to talk about the weak elements of how we determined this, and then also how do we determine the hotspot.

MR. PATTEN: Good morning, everyone. As Ron alluded to already this morning, he has talked about at this point basically everything out here in terms of megawatt solutions. He has gone over that and the results that were found from the analysis that we've done.

What I'm going to talk about now is how we identified the weak elements. And from there move into definitions of the terms that Ron has been talking about this morning, with the system reliability index. And talking about how we located the hotspot. And use those for the determination of the megawatt solutions.

Now, for the determination of the weak elements we used a combination, of course, of a power flow analysis and the contingency analysis to determine where the weak elements were located and come up with a security index for the system in California based on those weak elements. And, of course, you've seen many visualizations already that Ron has gone through that show you what the results look like as we identified the hotspot on a statewide visualization.

You've seen this example. This is an example of a small system operating under normal conditions. We have no overloads that are occurring on here currently. However, under contingency what we oftentimes expect to see are one or more elements that become overloaded due to a fault on a line or element somewhere on the system. We call this a weak element.

So in this case we have the line from 3 to 2 overloaded by 156 percent because of the loss of the line from 3 to 4.

So, what's the solution for this? Well, we can say either we need to put in a new line to buss 3, or we need to add new generation at buss 3. We can make that determination easily in this small case, however it's not so easy in a larger case, which is why we had to come up with the methodology for determining good locations to put generation.

The contingency analysis helps us analyze the security of the system and the ability to withstand equipment failure, where are the weak elements located due to the contingencies. And the standard approach for us was to perform a single, or what's termed an N-1 contingency analysis simulation using the emergency ratings for the transmission lines in the California system. And then, of course, to come up with some ranking method to demonstrate how we can prioritize some transmission planning, or in this case, generation injection to mitigate some of these overloads.

The identification of weak elements for California, we needed to simulate over 6000 contingencies. So that was 6000 separate low flow analyses run for every case every year that we analyzed. Each contingency itself oftentimes resulted in not just a single overload, but several overloads. So, we identified, and this should say weak elements here, numerous weak elements per contingency.

For California we started out doing 2003, '5 and '7. We moved on and did 2010 and '17 added on later. 2003 became our reference. And so for a reference we looked at 170 total violating contingencies out of the 6000-plus run. This means that 170 contingencies caused at least one overload somewhere on that system; 255 violations total occurred for those 170 violating contingencies. And those 255 contingency violations were on 146 unique weak elements. So we were able to identify 146 weak elements in California.

A little bit of a summary going out to 2005 and 2007 shows how the number of violating contingencies increased in each year that we analyzed. Of course, this is due to the load growth that was being projected in 2005 and 2007 without any additions to the system.

So we weren't changing any of the topology of the system at all. Due to that we were experiencing more violating contingencies, and consequently higher violations per year and more weak element identifications per year.

Breaking those down a little bit into area, we were able to pick out where those weak elements were located. And you can see that most of those were popping up for the scenarios that we had in the PG&E area; some in southern California; and a few in Los Angeles and San Diego.

Now that we have the weak element locations, the question was now that we have weak elements can we identify where we can inject power to try to mitigate some of those overloads that were occurring; not necessarily in total, but at least in part. How can we at least try and reduce the severity of those overloads.

So if you recall we had our contingency example that we looked at briefly before where we had an element identified as a weak element. And again, we said well either we need new generation or we need transmission planning. So let's focus on the new generation. How can we identify in general for a large system where we want to put new generation.

So our main strategy was to treat most of the system as just a pool out there. We have our overloaded line and what we want to know is can we figure out where to put a new source so that the transfer from that source helps mitigate overloads on the weak elements by creating counterflows on those elements to reduce their overload amount.

So, we examined that strategically locating the generation to produce counterflows. And what we get from that is a reduction of congestion and maybe some potential to avoid or delay the need of some transmission expansion.

In some of the examples you've seen from Ron that was the case, where there was no real transmission expansion needed. But in other cases, even with some of the sites that he studied, even in order to get the potential that he was expecting, there was transmission expansion that was still needed. So it is possible, though, you might be able to avoid, or at least delay, that expansion with some of these mitigations of overloads.

So the new injection of power requires decreasing generation somewhere else because we're considering a snapshot in time. In this case we were looking at summer peak scenarios for the different years. So we were assuming a load fixed for that summer peak condition.

So a good assumption was to assume that as we look at injecting new generation, that we decrease generation across the system, or across each control area as a whole. In other words, we're spreading that redistribution of generation out across all of the existing generators in each area over the system.

Now, the primary keys we want to get out of this are how do we come up with this calculation. What sensitivities, what mathematics can we use to identify where the good busses or locations in the system for injecting power to get benefit to the entire system.

And to start that off we started with a commonly used current calculation which is called the TLR, or the transmission loading relief. And what this does is this tells you how a new injection at a specific buss in the system will impact the flows on a transmission element that you look at. So in other words, it gives you a sensitive number that says I can inject power at this buss and it's either a positive or negative sensitivity that says it will improve the flow on an element by a certain amount for every megawatt injected at that buss, or it will harm the flow on that element by a certain amount for every megawatt injected at a buss. So that TLR is a one-to-one that we look at a single buss and we say how does it affect a single element.

Now this is the value that Ron has been using over and over in his examples. And we have two slides on the definition of that for that reason. This is what we came up with for our system reliability index. And it's called the aggregated megawatt contingency overload.

Now, what this number represents is a

sum of the overload flow on each element. So consider it right now, we're looking at it on an element-by-element basis. So for a single element several contingencies may cause varying degrees of overload on that single element throughout the course of the contingency analysis studies that we've run.

The amount of the overload above 100 percent on that element can be multiplied by the element's rating. So each element has a rating. And what's nice about that is that an element's rating is really proportional to its voltage level. So the higher the voltage level, the higher the rating on an element.

So it actually works as an effective way to scale these percentage overloads to come up with a term of severity for overload. As you can imagine, if you have a line overloaded by 300 percent, you're taking 200 times its rating. If that's a high voltage line you're going to get a very large number. If it's a low voltage line which has a very low rating, you're going to get a much smaller number.

So now we have a way of comparison. And saying that a 200 percent overload on a low voltage line equates to a different amount of megawatt overload than a 200 percent overload on a large line.

Now what we do then is we take the sum of each overload percent times the rating for every single contingency that was processed for a specific element, and we sum those up for the element. And that sum becomes the aggregated megawatt contingency overload for that element.

Now, what this can be used for is an indicator of element strength. So if an element has an aggregated megawatt contingency overload of zero what that really means is that no overloads occurred on that line for any of the contingencies that were studied. So we can say that element is secure.

However, elements with nonzero megawatt contingency overloads exhibit security issues of some kind. And the higher the value of the megawatt contingency overload on an element the weaker the element appears to be.

Now, we can take each element's aggregated megawatt contingency overload and we can sum them for a region. It can be an area; it can be a subsystem; it can be the entire system, which in this case we did for the State of California. And you can calculate that sum to give you an overall system or statewide aggregated megawatt contingency overload total.

That becomes the index that was used for doing the injection studies that Ron gave you the results for earlier. Because now what we can do is we can actually put in these new injections. We can re-run the contingency analyses and recompute the aggregated megawatt contingency overloads, and we can give you an indication of how much did it improve this reliability index for the system by putting in these new injections. And those become the indices that Ron was giving you before.

And this works well as a baseline for examining the effects on the system security as the system continues to grow. However, whether the actual number that you get for a particular year is good or bad is a matter of policy. Somebody has to define what that threshold for good versus bad is. We did not get into that here in this analysis.

What we wanted was to start with 2003; come up with this aggregated megawatt contingency overload value; and use that as a baseline for examining how much did that increase, moving forward to the additional years that we studied. And then, of course, how can we effect that by injecting some of the renewable resource generation in different locations that come up as hotspot.

Now, how did we determine what the hotspot were. In other words, where do we inject this generation. Well, that becomes what's called the weighted transmission loading relief. So if you picture back three slides, we talked about the transmission loading relief value. The weighted transmission loading relief is now a combination of the megawatt contingency overload values and the TLR values.

So we get an aggregated megawatt contingency overload number for each element, each transmission line. We also get TLR effects on that transmission line from all the busses in the system. So we can weight those TLRs by the aggregated megawatt contingency overload for each element. And what we come up with is a sensitivity or a metric of how much the total system or region megawatt contingency overload can be improved with a one megawatt injection.

And it says each buss here, I just want to clarify that's at a particular buss. We're looking at if I injected at this buss how much does it increase the system. If I inject it now instead at this buss over here, how much does it increase the system.

And as you can imagine, busses that have higher TLR values and branches that have higher aggregated megawatt contingency overload values will result in having a higher WTLR for that buss.

And what this means is that injection at that buss will have greater potential for system improvement.

The meaning of this, a WTLR of 4 at a buss means that for a one megawatt increase of generation injected at that buss, it's likely to reduce the total system aggregated megawatt contingency overload by for. So what this is, is the sensitivity value. For one megawatt injected at a point, how much can I decrease the total system megawatt contingency overload value.

So, if you have a positive value, of course, you're making it worse. If you've got a negative value you're making it better in terms of the aggregated megawatt contingency overload.

Now, what I'm going to show you next is a slide of new generation locations, and I think you've seen this already before in many cases. This is just an overview of California, and as Ron has talked about many times, the yellow locations are locations where WTLRs are fairly low, maybe somewhere around zero or slightly positive.

Where they're red they're much higher WTLRs, which tell us that for every one megawatt we inject at those locations we have a greater impact on reducing the potential for overloads in the system under contingency.

The blue locations, not necessarily bad locations, but in this case they tell us that the system may become more overloaded if we leave it in its present state. So, in other words, transmission would already need to be expanded before we could begin injecting generation at those locations that are coming up blue without additional transmission expansion.

This just shows for 2003 and 2005 the southern part of the state. This is a closeup view of some of the hotspot. You can see where we have some high impact busses around San Mateo, Alameda. And if we could inject power at those locations we would have greater impacts for reducing the total overload possibility that exists in the state due to contingency analysis data that we have run.

Moving forward just to look at the 2007 results that we had. You can see northern and southern California where our hotspot, high WTLRs and low WTLRs existed. And we also, of course, ran these numbers for 2010 and 2017, as well. And you can see how those hotspot are becoming more severe moving forward, because again all we were looking at was the state of the system, the topology of the system without any real transmission expansion being modeled yet. We just wanted to look at it as it was and see how it progressed moving forward across additional years, and where our WTLRs were showing the greatest potential benefit and the greatest potential harm without any transmission expansion.

Now, these weak elements, moving forward, because we didn't have transmission expansion really modeled, they show an identifiable spatial distribution year to year. So the beneficial locations thus also have a consistent spatial pattern.

What this means is that the projected solutions do not affect significantly the spatial representation of beneficial locations, and therefore new solutions at beneficial locations that are implemented in earlier years, 2005, 2007, will still be beneficial to the system moving forward when we look into the 2010 and 2017 states.

Now, these are the total aggregate megawatt contingency overload values that were computed for the 2003, '5 and '7 cases. So we see at the bottom we have the system totals. We see 8552 at 2003; that reliability index or AGAMWCO increased to 10,500 for the 2005 case, and up to almost 14,000 in 2007. And you can imagine as we keep moving forward with additional years and load growth continues, those values also continue to grow.

Now, given a set of proposed projects for distributed generation we can determine the reliability level versus different levels of penetration of new generation. What this just explains to you is all of the results that Ron has already shown you earlier this morning.

We are able to show how that AMWCO value either increased or decreased with these new generation injections. But what this also allows us to do is to plot the aggregate megawatt contingency overload versus new penetration level.

So here is an example for 2003, '5 and '7, that we were able to run; and this took numerous, and by numerous I mean several potentially hundred, analyses calculations where we took the hotspot that showed the greatest potential for system benefit and we began injecting incremental megawatts at all of those busses. And examining for those megawatt increases how did the total aggregate megawatt contingency overload begin to decrease. And we came up with these plots.

So, what we get, for example, in the 2007 plot there is that for the change in new generation that we inject from one step to the next, how much does that decrease the aggregate megawatt contingency overload.

At some point we could inject a certain amount of power that would actually get us down to the same reliability level that we had in the basecase. And, again, by plotting these curves we were able to identify that very easily.

So we have this yellow dashed line indicating where the baseline was in the 2003 case. We have these curves plotted. We can immediately go across and figure out that we would need a little over 500 megawatts in the 2005 year to have the same level of reliability that we had in 2003. And if we went out to 2007 we would have to have injected a little over 1000, almost 1100 megawatts of new generation, again to keep the same level of reliability index that we had in 2003.

Now, this can be used to determine that required level of penetration to achieve a certain liability target, and while in that previous example I was showing you a reliability target equal to the baseline that we had in 2003, again that baseline can be moved.

So what is we say we would rather have that reliability amount, that aggregate megawatt contingency overload value, be something less than what we had in the baseline. What if we wanted it to be 7300 instead of 8552. Again, who comes up with that number, you know, we don't know, we haven't gotten into all of the policy issues that would come into play with determining what that number should be.

But just theoretically speaking let's say we want to get that new desired level of 7300. Well, approximately how much generation should be installed? We already have these curves plotted. So all we have to do is go back to the curve; draw ourselves a new line from 7300 out to whatever year we're interested in. In this case we did 2005. And said, okay, we've got the curve. We've already plotted it. All we have to do is say we've got a new baseline for our reliability index that we want to shoot for, how much generation do we need to install in strategic locations to approximately achieve that.

And we can again look straight across and down and figure out we need approximately 950 megawatts to achieve a new baseline of 7300 for the aggregate megawatt contingency overload. Comparing that to 500 that we needed to get to the original baseline of 8552.

So these plots are very nice. While they take some computation to evaluate, they're very nice for this purpose of identifying for any reliability index level that we want to shoot for, we can go and immediately approximate how much generation it would take to be injected strategically to come up with that new index.

Now these slides you've already seen. They were part of George's presentation this morning. But I just want to reiterate that the 2003 case was used for calibration and for identifying a baseline aggregate megawatt contingency overload.

What was important for us, then, moving forward to 2005 and 2007, was plotting those hotspot and using those hotspot to overlay with the GIS information. And to examine also what their reliability indexes were growing to.

So for 2005 we identified the new number of contingencies and the new aggregate megawatt contingency overload for 2005, and again for 2007. And also for 2010 and 2017. So that's what these slides are here, just providing you with the information on how they were growing in terms of potential reliability index. And, again, we used that information for overlaying with GIS information in figuring out where the resources were located and then how can we do the studies and put in the injections at those positive locations where the WTLRs indicated we'd get the greatest benefit.

So that overlay, and this analysis that we've done here, that overlay with GIS was what we were shooting for for our identification of where to locate the renewable -- or where to locate the generation at the renewable resource locations.

A couple more slides here, just to point out something that we didn't really get into, but is important to recognize with this aggregate megawatt contingency overload. And that is we've been doing it on a systemwide level for all voltage levels up till now in our descriptions and definitions.

However, it's very easy to pull those apart by voltage level and actually identify the aggregate megawatt contingency overload numbers by voltage level. So what this gives us then is the ability to identify what voltage levels of transmission are actually experiencing the greatest amount of the contingency overloads during the analysis.

And it's an interesting thing to look at obviously. At this point we don't go into any analysis specifically by voltage level, but it may provide some additional information moving forward that we could use at a later date.

And in summary here, for why we used a unique criteria in this manner for identifying what we call the hotspot, is we tried to avoid a battle of the models. You saw as we went across each year we got a very consistent pattern of the reliability index. And we were looking for that in order to make comparisons. It allows for those comparisons of alternatives on a common format so we can look at injecting megawatts at different points and come up with a common reference that we can compare those to.

And, again, the indices that you saw in the results showed that. And it evaluates the overall reliability of the system, using a contingency based technique. And it allows us to evaluate the benefits of different voltage-based solutions on a common format, as well, moving forward if we wish to do that.

So, with that, I'll hand it back to Ron to conclude this morning session.

UNIDENTIFIED SPEAKER: Excuse me, you used the words transmission security, and then you used the words transmission reliability. I don't understand, is that the same thing or do you have a specific reason (inaudible) to talk about -- security?

MR. PATTEN: It should be the same thing in this reference.

MR. DAVIS: I'm going to kind of wrap things up as to what we did and what we were looking at. But I want to go back to this slide here for a minute.

One of the things we can do because we can separate these out into voltages, we can begin to look at their reliability and their security within the system by voltage type.

And it's interesting that you can see that the, for example, the 230 system here looks like it has an increase, it has a continual increase into -- the system continues to have higher contingency overloads as we go out in time.

The 115 area looks like it has an increase and a decrease. In the 2003 through '7 time period we did have power plant additions, and we had power plant retirements, and we had some changes in the transmission system. And so as we're modeling these they did have some impact on it.

But I think what's important on this, looking at this, is we begin to look to see how the trends are happening on our transmission system. We can see that the 500 is becoming to have a higher contingency overload as we're continuing to import more power on the system. And it becomes to be more dependent on us bringing power in from outside areas and transporting power around the system. It becomes more at risk.

One of the problems we have is we don't have a real good database, we need more expansion on the 69 in order to see its true impact. And one of the things that's really missing is a lot of the municipal and irrigation data that we really need to expand on and bring them into play, and add more into it, and even in some of the other areas that we didn't get modeled.

So, we really feel that we need more work and more cooperation. And because we were time constrained we didn't have a lot of time to work with the municipal utilities. But we really need to work to expand the 69 and to get a better handle on what those numbers are. But this is really a good indication of what's happening on the system.

One of the other things that this is valuable to look at is as we continue to expand the 500, that doesn't necessarily say we're improving the reliability of the lower system. And that allows us to look at maybe we should also be looking at what we need to do to keep strengthening and improving our 69, 115 and 230 system.

And one of the things that happens when we talk about this contingency overload and this impact ratio is, as you can see on here, doing improvements to the 500 improves the 500 and may do some improvements to the 230.

As we move down into the lower voltages and we put generation closer to the load centers, as we improve the 69 or the 115, it also has the effect of reducing the overloads in the higher voltages and improving those.

And so by strategically locating renewables at different locations we can provide the benefit as we move up in the voltage level. So not only installing things in the 500 is always a good thing, but we need to look at where we should put renewables or new generation closer to the load centers and have value.

Our object and our conclusions on this is we're not trying to be transmission planners for the utilities. We're not trying to dictate where renewables should be built. We gave you some examples today of some locations and how we can evaluate them and how we can look at them.

So, we're not trying to say and we're not trying to be the transmission planners and we're not trying to be the resource planners for the utilities, but rather we're trying just to give you an idea that if we start picking locations, are the locations provide a benefit to the system rather than just installing them anywhere.

The other objective in what we wanted to do was develop a common format for comparing different alternatives. We want to develop a way that we can now compare renewables to putting in a conventional, to putting in a transmission line. We wanted some way of evaluating these on a common format.

We feel that this methodology we created allows us to compare alternatives and common playing fields, as I said. One of the difficulties that we've had, and I'll put it in here, was getting the GIS mapping and getting all the naming conventions the same. And that was really difficult and we spent a lot of time on getting the conventions and the mapping correct on this.

You know, as we do power flows we used WECC standard format, and in the mapping office at the Commission they use a different naming and a different numbering sequence. And in the production costing that's done by the electric supply office, they use a third.

So, as I talk this afternoon when I get into it, I'm going to have some areas that don't have any real GIS mapping coordinates. We weren't able to get 100 percent. I think we got to 85 or 90 percent accuracy in tying all these busses, all the 6000 busses to a GIS location. We got to somewhere between 85 and 90 percent accuracy.

We stopped there because it really becomes time consuming. And so we need to work, one of the things we need to do is work closely with the Commission and others on getting more accuracy on how do we tie these together.

We feel the tool is powerful; it's accurate; and it's very flexible. We feel that it allows a lot of different people to come in from the developers, the utilities, the Commission, and be able to evaluate these and begin to look at things on a common basis, and be able to look at them and come up with some value, putting them in.

But I want to stress that we're not -- the analysis and the examples I came up today, there's going to be transmission planners are going to come and say, well, that buss, you can't install that transformer. There's no more room or that right-of-way isn't big enough.

That's why we really need to be looking at bringing people in together, bringing the experts in to know what their system looks like and be able to look and work on tying these together, and look at the benefits -- look at them in a better location.

But we feel in our analysis we're going to show this afternoon this works really well for distributed generation. Because now installing them on the distribution end, and we can look at the impacts they move up through the voltage from the 12 kV up to the 69, to the 115 as a benefit. We can also look at central station transmission upgrades, and conventional plants.

What do we need to be doing? Some of the things we need to be doing is really need input from the utilities. What are your resource needs? We can -- what kind of resources and what technology mix do we need. Do we need baseload, intermediate peaking. It's one thing to be able to look at a lot of wind penetration, but if utilities need baseload generation, then there's a mix we need to be looking at as we're looking at renewables and their benefit to the system. We also have to look at what kind of technology we should be looking at, and how to integrate them.

Transmission power flows, as you know, is only a snapshot in time. And so what we really need to be also is incorporating into a power simulation model. So as we're installing wind generation we need to look at what impact does it have over the entire year; and how does its capacity factor fit into what the resource needs are of the utility.

And we really need the interaction between the Commission, the utilities and the developers to insure proper and timely development. We're not here to say this is what you should be doing; these are examples of what can be done. But we really need everybody to come together and to look at this and say how can we work together to find locations and provide a benefit.

And that's all I had.

MR. SIMONS: Thanks, Ron. I want to go back to something -- I'm going to pull up a slide that I presented earlier. And it has to do with the fact that this is really a multi-chaptered book.

When we start talking about, you know, what needs to be done, there are a number of things here, okay. And ultimately what we'd like to do is really look both at the state, as a whole; look at the state in terms of the overall region; and look at particular areas within the state.

I think it's pretty clear to most people when we start talking about bulk renewables that the greatest amount of resources right now in California are down in the southeastern portion of California. The wind resources in the Tehachapi area are immense. Geothermal down in the Imperial Valley, very great.

So when we start looking at those

potentials, we're really going to have to focus in on those specific areas.

Now, one of the things that I really didn't mention today, but it ties very importantly in here, is the regional statewide study groups. Dave Olsen from CEERT, the Center for Energy Efficiency and Renewable Technologies, has been participating in the Tehachapi study group on our behalf to figure out what's going on down there and what role can we play in that.

We know that there's going to be a Salton Sea study group. There's possibly going to be a northern California study group. We think it's going to behoove us to try to build in some of the analyses that we're doing here; to work closely with the ISO; to work closely with the irrigation districts, with the munis, with the utilities, to try to figure out what role should renewables play in these regional study groups.

We also know with the work from electronics, looking at again what's going on across the other states adjacent to California. How are we going to fit all of this in so that as we develop transmission out to the future it's transmission that supplies benefit regardless of whether it's renewable or conventional. That it's going to build well into the system. And also meet the needs of the WECC. And we're not isolated from the rest of the western grid.

So, again, I just wanted to make that point, that as we go into this, this is really, just view this as the first chapter, an introduction to some of the analyses that we've done to date. We want to engage all of the stakeholders to build further into this. And we think that's going to be a very important ingredient.

And one of the things that, again, we want to get input from folks about, how do we best do that. And what role can the various stakeholders play in that.

We have a little bit of time so what I'd like to do now is go ahead and open this up for some public questions and discussion. I would mention that if you're going to make a comment, please go ahead and step up to a microphone, clearly identify your name and the organization that you're representing.

DR. TOOKER: George, I have a question. Early on at the beginning of the workshop you talked about making this information available. When do you plan on putting that up on the web? And what are you going to be putting on the web?

MR. SIMONS: Well, we'll have all the presentations up on the web. Now, I talked to our web folks. The analyses that we've done, which includes the power flow analyses, the GIS, is a very large amount of information, literally between 60 to 100 megabytes of material.

So I've been playing around with do we try to create an FTP site where people can download that, or do we want to just simply create a CD that has the analyses, and then have people contact us and we can mail out the CD.

The web folks people were very reluctant to start putting, you know, large amounts of material like that on the website because of the traffic it would create.

So I think at this point in time we will put this -- we already have a CD that has a lot of this information. What I want to do is make certain that it's easily catalogued so people can go into the CD. One of the problems we've had in the past, even internally, is people looking at the huge amounts of material and getting confused as to what really do they want to look at.

But we will make it publicly available via, sounds like the best idea is, a CD. And we will have a contact person or people that folks can get in contact with and we'll rapidly mail those out.

I would anticipate having that CD done by next week.

Again, it's open for comments. If anybody does have comment or question, please feel free to come up to the dais and identify yourself.

MR. SPARKS: I'm Robert Sparks from the California ISO. I just had a couple observations or comments. I think it is useful information that these tools could provide. Just had some thoughts on the reliability benefits, and I was trying to follow as closely as I could a lot of detail there.

From what it looked like generation was installed on these busses where there were contingency overloads and it was assumed that -- I mean I'm sure you probably have thought about this already, but it looked like it was assumed that generation would always be there, would always be providing this reliability benefit.

But obviously, mostly in the wind generation case, you know, what benefit is it going to provide when the wind stops blowing. You still may need to build another transmission line. And if you already have a redundant transmission system that almost provides no benefit, you go back and redo the analysis after you've installed this transmission line that you have to install because the wind generation isn't there 60 percent of the time, the benefit is, you know, less or zero. So I'm sure you thought about that. But it just wasn't mentioned.

And the other thing was talking about summer peak value or, you know, the amount of generation that could be installed during summer peak. Obviously it would be useful also to look at lower load conditions. Again, if it's a wind generation, it seems to be many areas the wind blows more when it's not hot than when it is hot.

But I think, aside from addressing some details, I'm sure there's many more, I think that it is a good powerful tool, and the visualization does help everyone understand, especially more than just myself who sits in front of a computer and probably needs those visualizations a little less, but it's still nice.

MR. SIMONS: Thank you. I do want to comment that within the transmission analysis we looked at spring, summer and winter. There's another effort that has been conducted under the California Wind Energy Collaborative. It actually isn't just the wind group. It involves the National Renewable Energy Laboratory, Oak Ridge National Laboratory, Cal-ISO, for example.

Looking at the intermittency nature of these different renewables, wind in particular, in looking at what would be the impact on the system. And it may actually have -- they came out last year with a phase one report. And we have just posted on our web, I believe a week ago or a week and a half ago, the phase three report, which looks at the effective load-carrying capacity on the system.

So, I totally agree that we need to integrate those two types of tools. We probably need to do some production cost modeling that Ron was talking about. So that, in fact, as we get these profiles that are developed we can look at, for example, the top 200 peak hours of the year. And as we load up the transmission line, what's going to be the impact.

We're not at that stage yet, but I totally agree, that's where we need to be.

MR. DAVIS: Yeah, maybe I didn't stress it enough on that, but I think we need to tie in and look at, especially when we get into wind and some of the intermittent resources, even solar, as to whether or not it fits into a whole peak period, spiking. And then how do we fill in the other part.

But as I said, we showed at Riverside where we had to load up that line, and then we weren't able to do anything more with it. If we're going to have to build any transmission upgrades, as I talked about, in Imperial, and we start building a 500, then can we integrate into a mix of resources that fit in so that we can put some of the wind onto the 500 kV line, some geothermal and still have areas to bring in additional power from the Arizona/New Mexico area.

But we do recognize that, and that's why we talked about needing to do a spring and a winter on a power flow and look at it, especially when we start getting into maintenance periods. And now we have to look at what happens when we have maintenance outages and we're doing renewables. And what's that do to the power flow and reliability of the area. Does that change that significantly, or do anything, or provide additional benefits during those other periods.

But we do need to tie that in. And we need to do it, look at integration. Integrating multiple and different technology types together. And so as we said at the beginning, we did these independently, but we did not look at combining and saying, what if I did so much geothermal in Imperial, so much wind in Riverside.

And so, yes, you're correct. We need to look at that. This was to show how the model could work, and the benefit it does. But now you can open up and see now how do we integrate this all together and develop a plan that works that meets the 20 percent, but continues to improve the transmission reliability.

Thank you.

MR. SKOWRONSKI: Mark Skowronski, Solargenix. I was kind of curious on the utilities transmission cost-ranking reports, which is appropriately named, because basically they just discuss the cost of transmission upgrades.

And in specific circumstances there you had some significant benefit, network benefits. How is that going to be integrated, the cost of the benefits?

MR. SIMONS: Well, again, what we haven't looked at is the complete mix, okay. And I think any sort of a sound approach is going to have to look at, first off, what are the highest needs within the state; and then secondly, what kind of solutions.

And those solutions could be a family of solutions. They could be transmission upgrades; they could be conventional generation; they could be, you know, DSM; they could be renewables.

And so part of this whole process, I think, is bringing all of these tools and all of these potential solutions into some sort of a mix and looking at them. And then doing a cost/ benefit analysis.

What Ron's group, DPC, really did is they, as an illustrative application, they said if we do these, if we bring in this amount of technical potential in this specific area, what would be the cost of upgrading the transmission. And then, you know, that gave you some sense of, okay, on a levelized cost basis, then, you know, am I out of whack. Am I talking about putting on 500 megawatts of wind, for example, that's going to cost 11 cents.

And I think what we are doing is a reality check that even with the transmission upgrades, to put in a certain amount of wind, for example, in that area, we were looking at still a four to five cent per kilowatt hour basis. So it was a reality check versus an absolute value.

Does that help?

MR. SKOWRONSKI: Well, I guess I'm still fuzzy with respect to how the process would impact the ranking report specifically. In other words, the transmission cost ranking report basically was just the cost of the transmission upgrades that would be required to install a wind park over in area A.

But in those areas where you've identified substantial network benefits, I don't see how that's going to be melded into the evaluation procedure of the renewables, as part of the bid evaluation process.

MR. SIMONS: I don't know -- okay, I have a better understanding. At first, I'm sorry, I misunderstood it. I don't know that the procurement process at this point in time does weigh those factors. I think again part of the process as we -- I mentioned we had a geothermal summit several months ago now.

One of the questions that those folks were asking is, well, wait a second, we think that some of the procurement processes don't take into account certain things with geothermal.

And my advice to them was well, then you really need to get involved into the procurement process. It's probably too late for this year. But if you think that those things, those factors have to be taken into account, then it's really incumbent upon you to do that.

Again, I think as we begin to go out through these renewables transmission planning study groups and the statewide analysis I think, you know, again we're going to involve utilities, the PUC, Cal-ISO. So I think those messages will surface to the top.

MR. FRANK: Dan Frank with San Diego Gas and Electric. The question I had was in regards to the study groups that you mentioned about the Salton Sea study.

I was curious about the timing of that. And also are there going to be other study groups that may look at, for example, the wind potential in Riverside and also the wind potential down in San Diego County.

MR. SIMONS: I'm not certainly conversant in this. Dave perhaps can, Dave Olsen has been participating in the Tehachapi study group. Dave, could you address that?

MR. OLSEN: Sure. No date has been set yet for formation of the Salton Sea study group. But SDG&E, Cal Energy and Imperial Irrigation District are all quite enthusiastic about an early start. So we're thinking about a date of late October for the first meeting.

MR. DAVIS: Just one comment on San Diego. I know that it's interesting when we talk about the study groups down here, but we did not look at the 500 kV line. But I guess on the Miguel 500 kV line, in looking at the wind development in San Diego County, and also some of the wind development in Imperial County on the western portion of the County, I think that provides a value to do some analysis to look at how much more value does that provide in building that 500 kV line. That not only you're bringing power in from the Arizona/New Mexico border, but you're also expanding and bringing that power in that looks like it could be developed in that San Diego County.

So it's really a good fit to look at, as that line is being proposed and developed, to look at that development and how you would get that power out from the wind site.

MR. SIMONS: Commissioners Geesman or Pfannenstiel, do either of you have a comment on the study groups?

PRESIDING MEMBER GEESMAN: A couple of comments. One is it relates to Mark Skowronski's question about evaluating the benefits of network upgrades. I think, as you know, Mark, that is the black box in the review process that currently transmission planning undergoes.

And I think that this Commission has made fairly clear over the past couple of years its skepticism that we are accurately capturing the full benefit of transmission upgrades. I think that will be one of the themes that you'll see visible in the 2004 Integrated Energy Policy Report, a draft of which we'll be releasing the middle of this week.

And as it related to the San Diego comment, in the long-term procurement filings that San Diego has made with the CPUC, they make fairly clear the need for either a greater north/south connection of their system to the rest of the state, or a greater east/west connection on the high voltage system, or perhaps both, as being necessary for their ability to achieve their 2010 renewable portfolio standard goals.

And I think that's a theme that you'll see the state increasingly forced to address. The extent to which we hold these renewable goals to be primary objectives of state policy, and the requisite level of transmission upgrade that will necessarily have to go along with them, is something that I think the state is only now trying to come to grips with.

COMMISSIONER PFANNENSTIEL: I'd just like to say that I thought that the model results and actually the model itself, that we heard about this morning was actually fascinating. It was really an interesting way of gathering together a lot of information and trying to make some sense of some of the questions that we're struggling with.

And I'm quite interested in the next step which I see as bringing in the other stakeholders in this, the other parties, the utilities, the munis, those who are doing this kind of work in a different way using different models.

I think that we'll all be better informed once we get all of the rest of the stakeholders into this discussion. Thanks.

MS. THOMAS: I'm Chifong Thomas, Pacific Gas and Electric. Just a couple comments. I'm echoing Robert Sparks, the comments on the integration; and also looking at lower load levels. And also at the same time you probably need to look in the next step different system conditions that -- I think the WECC has databanks that can be readily available to be used.

The other thing I'm kind of curious, just a clarification. It seems like at one point I thought that you're using a 2003 system, and just escalate the load without putting in -- reflecting the system upgrade that would be occurring between 2003, 2005 and 2007.

But in the latest discussion seems like

you had used different basecases for 2005 and 2007 and 2017. Which part was it?

MR. DAVIS: Okay, we didn't get into the database development in here due to the amount of data we had to do. We actually went out to the utilities and went to the IOUs, PG&E, San Diego and Southern California Edison and received their databases, their latest databases for 2003, '5 and '7.

So we had their data sets for what they represented as to what the load flows and what would be available during those periods.

The Commission had also wanted certain generation additions, certain retirements and certain transmission changes, modifications they wanted to make. And those got incorporated into 2005 and '7.

To get the '10 and '17, nobody really had any load flows at that point, so we had to make some general assumptions on load growth. And we worked with the renewables group who did some forecasting and also with electricity supply office that does production costing. And worked with them on doing some load forecasting at the Commission to look at some load growths out in that period of 2010 and '17.

But we did try to incorporate everything that the utilities had planned. And we went directly to, for example, PG&E and got their '3, '5 and '7 from them and used those. And then we merged the data sets together.

So we took the individual utilities and we merged the data sets together; and then made sure the inter- and intra-power flows matched.

MS. THOMAS: One more question. It's on the cost of transmission upgrade, that you use a generic type cost, standard cost. Did you look into, or is any plan to incorporate environmental mitigation into the transmission right-of-way acquisition?

MR. DAVIS: Yeah, because we're trying to do, showing how the model can use and do some demonstrations, what we did is we went to EPRI, as I said before, and some other areas, and we developed some generic costs. We had, for example, on 69 and 115 we had so many dollars per mile of transmission lines.

We did not get into whether or not the conductor size or the power configuration as to what each individual line would look like. We come up with a standard cost per mile for a transmission line, and a standard cost per megawatt of substation costs to build a substation.

The idea was to develop some costs that could be used throughout the different alternatives to be able to evaluate them.

As we get into looking at Solano or getting into looking at more detail that's where we need the utilities to come in. Because I note in the, I believe it was the Solano, there was a lot of additional higher costs that PG&E came up with because they had to cross over the river, and they had to do some other mitigation measures that had to come into play. And that's really nothing that from our point that we can do.

But we really need the utilities to come in, once we pick an area, that we work with them in getting an idea on the better costs.

Public benefits is something we haven't included in there; that if we do one alternative to another, does it improve transmission; and what is its value; and how do we weight one alternative versus another as to its value of providing other public benefits. I think that's what you were asking on that.

MS. THOMAS: Yes. Actually I was wondering if the transmission costs you had put in, does it include right-of-way costs, or just a straight transmission design and built.

MR. DAVIS: It's straight transmission; we did not try to do anything on the right-of-way, because we didn't know exactly on the route and, as I said, we were trying just to have costs that we could do comparisons between. But that's where we really need the utilities to come in and the developers and say, well, here's what the additional costs, the additional parameters that we need to add on to those. And that's the additional things we need as we study these in more detail.

MS. THOMAS: Okay, thank you.

MR. SIMONS: I also just wanted to mention that we do have a group within PIER that's looking at the right-of-way corridors. At some point in time I think we'd try to integrate that in.

And in addition, Tony was telling me that the transmission cost does include an adder for right-of-way. It's a generic adder; it's not site-specific. But I, again, would echo what Ron has to say, which is this is one of the reasons why we need to move forward with getting additional input on this stuff.

MR. TOOLSON: My name's Eric Toolson; I'm with Pinnacle Consulting. I have two clarifying questions.

The first one, if I understand the contingency analysis correctly, you take an element out and you see what the overload is on a particular line or other lines.

At that point do you look at any type of mitigating action such as generation redispatch or commitment? Or is that not typically that part of a contingency type study?

MR. DAVIS: In this analysis we did not take any, so to speak, remedial action schemes into account. Certainly if you were going to be doing a much more detailed analysis of what you actually expect for benefit, taking all of the considerations into account you would come up with a more defined version of a contingency set that you would run to come up with these numbers. And then do your injections and recompare.

And those could include contingencies

that have, as part of those contingency definitions, remedial action schemes of other lines opening or closing, generation redispatching, load dropping and things of that type.

But for these preliminary analyses we just looked at straight opening of lines with no remedial action schemes whatsoever to examine how the system responded to that singular outage.

MR. TOOLSON: Thank you. The second question is more of a higher level policy question. You've developed this framework; it gives us an indication of the reliability impact of various projects and injection points.

Is it your intention to use this as a stand-alone measure of reliability, or eventually to weight this with the cost or put an economic value onto it?

I realize you're limited in what you can do at this point in the study due to your resource constraints, but what's the long-term intent there? How will it be evaluated, for instance, a project that has a greater reliability benefit but costs a little bit more? Do we have any way of trading that off currently?

MR. DAVIS: Well, we're lucky because we've got the policy thinkers here with us, so they can answer that and take me off the hook.

PRESIDING MEMBER GEESMAN: Not a chance.

(Laughter.)

MR. TOOLSON: Thank you.

MR. DAVIS: One of the things we talked about that is, you know, as we get into this is looking at congestion zones the ISO comes up with and be able to incorporate those.

And then I think, as was said earlier, you know, the optimal power flows, looking at some of the redispatching, be able to do that. Here, again, time constraint prevented us from getting into that. And, you're right, as to our budget was looking at how can we make this work. And then what other things do we need to look at.

So, the questions you asked were very good, that we need to be expanding and looking at those. And those will impact the decisions as we go through this and look at these values.

MR. HAMMOND: Good morning; Richard Hammond, Optimal Technologies. I think this may be a question for George Simon, but I'm not sure.

In the slide at the beginning of the

presentation, what isn't covered, it was noted that reactive power has not been addressed in these models.

And I wonder if you could comment on what you would anticipate the inclusion of reactive power would offer, and how you anticipate going about the inclusion of that element.

Thank you.

MR. VISNESKY: You got me put up here at this podium. George is absolutely correct when he says that the focus of the analysis did not include a rigorous analysis of all the issues associated with reactive power.

But I can tell you, being intimately involved in the analysis and helping with the development of this tool, that we've seen some. And in fact, have chased some reactive-driven issues very very robustly with this model.

We've seen in our analysis significant issues associated with voltage stability, especially under contingency analysis and especially in cases where you're trying to inject generation in areas that it's already limited in terms of it ability to absorb a significant amount of extra reactive component.

So, we didn't specifically address voltage stability issues, but the model completely handles those in the sense that any normal powerflow program does. And we did see in many cases significant issues associated with system voltage stability and had to, in the process of doing our analysis, deal with voltage stability issues in significant areas of the system, in order to get solutions that would, in fact, converge.

So, it's modeled. The reactive limits of the generators are observed. The voltages are monitored as if they would be in any other specific load flow analysis.

And I think, to answer your question about how it could be carried on further, and to get to George's interest, when you have a situation, as you well know, where transmission issues and generation issues have to integrate into issues that are very much tied to low voltage level conditions, like additional load and possibly large amounts of distributed generation, that a voltage support and voltage stability become an issue that overlays, in many cases, the entire process.

It tends to be more driven from the dynamic components of it. In other words, redispatch then becomes a possible method of handling these rather than a specific static addition to the transmission system.

So we didn't go to that level because those are things that we certainly didn't have the budget to do. But I want to make everybody aware of the fact that we certainly did not ignore the normal parameters of voltage support in the dynamics of generation limits in this process of analysis.

Did that answer your question?

MR. SIMONS: The other comment I want to make is that one of the traps that we fall into is deciding that we want to perfect a model. I think it's going to be very important to get the stakeholders in here to find out what's really important.

If we're looking at meeting the RPS goals, I think we could spend a lot of time looking at how to come up with a perfect approach that I think will miss the entire target.

So, one of the things I'm watching out for is let's not get into over-analyzing and over-modeling something, rather than just getting on with the task of really developing a good sound approach.

Any comments from the Commissioners?

PRESIDING MEMBER GEESMAN: Yeah, I think we do need to give some thought, and certainly invite everybody here today to share your views with us, both in the workshop and in writing subsequently, as to what the most beneficial next steps can be to try to take some of these tools from the shelf or from what I'll characterize as an academic environment, into actual application.

The Commission, and I know the PUC and the ISO, I think each feels an active need to better engage the community of interest that are involved in transmission planning to adjust so that we have both a better framework for evaluating costs and benefits. And also a proactive capability to incorporate the state's desires for greater development of renewable resources.

I think that George and Ron have shown us some interesting tools available to assisting that process. And I'd very much invite comments and suggestions as to how we can make the greatest beneficial use of those new tools as next steps.

MR. SKOWRONSKI: Real quick, what is your schedule for the followups on this?

MR. SIMONS: Well, as I mentioned, we have some additional workshops planned for late October, November. The next step in terms of this particular element would be we do want to move forward with integrating the rest of renewables, and focusing in specifically on Salton Sea and Tehachapi to do the additional analysis to really look at how we can build out some of the technical potential there.

And then getting the documentation out to everybody so they can comment on it.

I have not been good with predicting accurately when this document will be finalized. It turns out that the analyses and the complications with getting the GIS lined up far outweighed what I thought it would take.

And so I've been saying, and I think the Commissioners got frustrated with hearing me say, well, it will be done in the next couple of months. We are very very close with the GIS analysis for the remaining renewables.

So, I'm hoping literally that we can

close that out and get that documentation out to everybody, again, by the end of the calendar year.

I do want to mention to folks that anybody who made a comment, there is a sign-up sheet when you come in; there's a table where you picked up some of these materials. If you could please sign your name there just simply so we have that on record, I'd appreciate it.

Are there any other questions or comments?

If not, then I guess we could break early for lunch. We are going to reconvene here at 1:00. The focus at that point in time will be on the distributed generation renewables, which is below the 69 kV level.

So we'll have Hank Zaininger, Snuller Price and then Ron Davis come back and talk specifically about case studies and aggregated DG. And that'll be at 1:00.

Thank you.

(Whereupon, at 11:35 a.m., the workshop was adjourned, to reconvene at 1:00 p.m., at this same location.)

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AFTERNOON SESSION

1:13 p.m.

MR. SIMONS: Again, this morning we covered both transmission renewables and the renewables transmission planning. This afternoon we're going to focus in on renewable distributed generation.

And when you start to look at specifically case studies, because, again, if we start talking about, you know, below the 69 kV level, there's miles and miles and miles of distribution line out there and substations.

And so we, early on, thought well, we really need to do some case studies because that's the only way we can handle the databases that are involved. Because, otherwise, if you try to do this statewide it quickly becomes a very difficult job.

So one of the case studies looks at southern California. And that's very nice, because again, southern California has its own particular situation.

Another series of case studies looks up at northern California. At some point in time they're going to expand that to look at

Sacramento. I think when you begin looking at a three-legged stool like that, you get a real good sense of how would distributed generation fit into a rural type setting versus an urban setting. And particularly in southern California, what do you do when you've got big environmental situations.

And so we're going to start off with Snuller Price from EEE talking about distributed generation in the Bay Area. We're then going to turn around and shift down to southern California and have Hank Zaininger look at the Chino Basin.

The two cases are very illustrative of, again, Bay Area very urban area, not necessarily viewed as having a lot of renewables. Versus southern California, the Chino Basin. For those of us who deal with dairy wastes, the Chino Basin is unique in that it has the highest concentration of dairy cattle in the world. So, again, there's a potential there to harvest or harness renewable resources.

And then at the last part of this we're going to shift over and look at how can we statewide begin to look at how do you aggregate renewable distributed generation resources so that, in fact, you can begin to filter down to what might be very interesting cases, and see what the systemwide impact would be.

At the end of that -- well, we'll take a break at 2:45, and then at the end of Ron Davis' discussion, at 3:45, we'll open it for public questions, discussion, and talk about some of the next steps. Not just the next steps to this afternoon's discussion, but also the next steps to this morning's discussion.

Snuller, why don't you go ahead and come on up. By the way, if anybody later on does intend to make a comment, if you'd go ahead and sign in at the back table, there's a sign-in sheet. Just so that we have your name and your company, we'd appreciate that.

MR. PRICE: Thank you, George. Can everybody hear me okay? Right here? Okay, perfect. Thanks.

Yeah, what I'm going to do today is walk through in about 45 minutes the summary of four different case studies looking at renewable distributed generation, focused in the Bay Area, as George had indicated, as well as here in Sacramento for SMUD.

I want to start by giving an overview of sort of our approach for what we're calling the renewable DG assessment project. Really we've tried to couple two aspects of our analysis, an economic analysis. So, is renewable distributed generation a cost effective resource. And an engineering analysis, how does renewable distributed generation fit into our distribution utility planning and operations, does it integrate.

And the idea with kind of combining both an economic perspective and an engineering perspective here, is that we want to find winners. All of the utilities that we're working with are really interested in doing renewable distributed generation applications. What we tried to do was set up a methodology that would screen through potential options and identify for them what the best opportunities were, both in terms of economics, as well as with the distribution engineering functions of the utility.

We focused on four case studies. The idea being that the learning from those four cases will translate to and be applicable to other parts of California. Okay, so it wasn't just we only wanted to do four case studies and stop there. We wanted to be able to try to draw some more general conclusions to the rest of the state. Hopefully winners for our four municipals will also be winners in other places.

So our project objectives were to develop economic and engineering screening. And I think screening is an important word in this because really what we wanted to do was not rule out potential options, but really cast the net wide and involve a lot of different renewable technologies. And then screen out those that don't look like they have as much potential and highlight those that do.

And again, we've been focusing with four municipal utility clients. So we've been focusing our analysis in terms of the decisionmaking that those types of utilities are making.

Our methodology has developed to one, identify best locations and timing for renewable DG. This morning with Ron's presentation we saw a lot about locations within the state. And what we're going to see with these case studies is locations within the city. Okay, so we've really narrowed it down; we're at much lower voltage on the distribution system than Ron Davis was with the transmission system.

We want to look at reliability impacts of renewable DG. I think every utility engineer we met with during these case studies was very interested in reliability. Okay, that's one of the number one issues for our municipal clients in these case studies.

And we also wanted to look at uncertainties. WE didn't want to do our analysis in sort of a static world with a certain set of assumptions. We wanted to be able to look at, well, when things move, like market prices, like natural gas prices, other inputs, rates, locational marginal pricing, other issues that are on the agendas in the state, how does that impact our answer.

A little bit about our project organization. Clearly we're under the PIER renewable project. And within that we're working under San Francisco PUC/Hetch Hetchy. Our program, with these four case studies, is just one of I think three different projects. There could be more under Hetch Hetchy.

We're Energy Environmental Economics. I don't know if people can see the pointer, right here. We really were doing the economic analysis. We partnered with ElectroTech Concepts to do the engineering side of the distribution engineering. So our shop in particular is not an engineering shop, it's an economic shop. But we've been coordinating this.

And then, of course, we worked with four different case studies. Alameda Power and Telecom, which is the City of Alameda, not the County. City of Palo Alto Utilities, obviously Palo Alto. Sacramento Municipal Utility District. As well as San Francisco PUC/Hetch Hetchy.

So although we're a sub to Hetch Hetchy, they're also doing -- we're also doing a case study for them, and I'll talk about that in a little bit.

In terms of our project status we're pretty far along. We've done an assessment for both Alameda Power and Telecom and City of Palo Alto Utilities; and done basically the reporting and analysis. The analysis is complete for SMUD; we're putting together the sort of documentation on that learning. And we're about half way done with the Hetch Hetchy analysis.

So, we're pretty far along, which means

I'm able to show you some pictures on both sides and get -- and show some results.

If I were to summarize, key results to date is that based on just direct costs and benefits, it's difficult to find cost effective renewable distributed generation. I don't know if that's a shock to anybody.

Avoided costs are too low. And I'm going to talk about in detail what I mean by avoided costs, but we're competing our renewable resource with bulk central station generation, transmission and distribution. And it's tough.

Renewable distributed generation capital costs are pretty high. Although a lot of them have free energy once you've purchased the unit, their capital costs are pretty high.

So, that leads us to another area of assessment, which is the indirect benefits. We're calling them often community benefits. And these are really important to our four municipal case studies. Cleaner air, having a pilot project in their area, other aspects that are not necessarily quantified as a direct benefit, that you're getting a check for -- writing a check out for. But that are still a big deal to the case studies.

If those are at the right level, and this is an assessment by the person at the utility making the decision to purchase, then there can be good renewable distributed generation applications.

The cost effective technologies, just looking at direct cost and benefits, tend to be combined heat and power applications. So this would be an application, say a landfill gas, that also is able to use the heat from the generator to create hot water that will offset maybe natural gas purchases or something else.

So those applications tend to rise to the top in terms of just net economics. And we'll look at the others, as well.

Another key -- and so far I've really highlighted economic findings. On the engineering side, and I think this echoes a bit on terms of what Ron found out on the transmission system, is that best locations within the distribution utility really make a difference.

So it's not that the generator is in Palo Alto. It's that the generator is actually in a location in Palo Alto that gives them the most benefit. And we found a significant difference between locations within a utility.

In particular with capacity release. So how much peak load does my municipal have on the system. And peak loss reductions. Generators at the end of line save more losses than those right at the bulk transmission interconnection point. And we've quantified that with the engineering analysis and monetized it with the economics.

So, just a quick overview on evaluation methodology for the economics. What I've got here is a flow chart of our sort of whole project from start to beginning (sic); and I've got in the slightly darker orange economic pieces of our project highlighted. And then we're going to do a similar chart when we go through the engineering results.

Our economic analysis starts with avoided costs. So, what are we displacing. What cost does that municipal utility save when they put in a renewable generator. So they don't have to buy as much energy on the wholesale market; they don't have to pay for as much transmission to their city; and sort of so on down the line. And we're going to go through what those are.

We take those and then compare with the

costs of building and installing that renewable generator. So we're now doing an economic screening analysis of what's cost effective. And I justify my investment with my avoided costs.

We already mentioned a little bit uncertainty analysis. We didn't want to do this as a static analysis. We wanted to be able to look at uncertainties. In about 10 or 15 minutes when I get there, we're going to be looking at the engineering. And there's some direct feedbacks. We already talked about if I put this in a location that saves more energy in terms of losses that's going to have a feedback to the economic model. As well as distribution capacity benefits, transmission capacity benefits and so on.

Finally, we're going to talk about the reliability analysis piece in the engineering and the way we put that together to answer is my system more reliable with renewable generation. And how do I quantify that.

So, looking at the economic screening, really at the simplest level it's pretty straightforward. We're just talking about a comparison of costs and benefits. We've taken a life cycle view of this. So we've gone out and looked at the whole time that generator's going to be there before it needs to be replaced.

When you kind of unbundle that it gets a little bit more complicated. The first question you ask is, well, whose costs and whose benefits. Okay. And we looked at a number of different perspectives because this looks very different if you're a commercial customer thinking about putting on rooftop PV, or you're the municipal utility that's looking at doing a PV roof program, or you take a more sort of community view and say, well, are costs higher or lower to serve our community with this program in place. So, perspectives are really key.

We're trying to do screening, so we didn't do a financial pro forma model that would be, you know, each year what are the costs and what are the benefits. That you would need to do before you actually went ahead with the project.

We were trying to screen through the whole list of potential projects to get those that are the best. The next step would be to do the pro forma. That would probably be wrapped up with an RFP process for the municipal, and then they could move forward with their project

DR. TOOKER: I have a question.

MR. PRICE: Yes.

DR. TOOKER: How did you or did you, in this first screening level, consider benefits such as improved air quality or job creation?

MR. PRICE: Yeah, I'm going to get to that. I can answer it quickly here and then we can go into more detail, because that's a really critical piece.

We did that by not trying to monetize those particular benefits and add them in as a benefit directly. What we did was compute the so-called direct costs and benefits; and then list out those indirect benefits.

Now, with this type of case setting we had the advantage of working with that public utility board that is making the decision. So the question is, if you get in the end, well, energy generated this way say costs a 1 cent premium over what it would on the wholesale market. And it has -- and that's just on direct cost benefits.

But that project also has these other indirect benefits, improved air quality, demonstration, just demonstrating renewable technology was important to these clients. Is that worth your 1 cent premium.

And since they're the ones making the decision in the investment, that's a useful approach for them. Because they can say, well, yeah. And, in fact, the City of Palo Alto, their board basically ruled on how much of a premium they're willing to do. They're willing to have a half a cent rate impact for their utility to get up to 20 percent renewable energy in their mix. So they ruled, okay, how much premium are we willing to tolerate.

And by working with the person making the decision, that indirect assessment and just a list of benefits makes it, because they can do a judgment.

And I've got the list of how we -- we tried to set up in our process a way of making that list and making sure it's complete. And I'll show that later.

Before we get there, I'd like to go through the direct costs and benefits. And for those that have done integrated resource planning or have really looked at this type of analysis, this may not be that new.

We didn't completely reinvent the wheel

here. What we've done is for renewable DG projects we've lined up what are the avoided costs for the utility and for the customer. So, for example, if I put in my generator I'm going to avoid some wholesale purchases. Now I've got in-area generation.

I'm going to avoid some distribution costs. We worked with the distribution planners at the utilities to identify what costs they would save.

Avoided transmission costs. All of the case studies, all of the municipal utilities that we worked with buy transmission services. So for municipal utility perspective avoided transmission costs are avoided payments to either the ISO or the investor-owned utility that owns the transmission route.

Improve reliability. How much is that. Depending on if this is a cut behind the customer type of application, and I've got my generator on my side of the meter, if I'm the customer, then bill savings was a really critical financial impact to the customer. How much money am I going to save. And so from that perspective of the customer bill savings is also a part of this.

Our approach was to estimate each of these components as accurately as we could with the resource planners at the utility; and then tabulate them up for different renewable generators at different locations.

On the flip side we had costs. And costs also depend on perspective. Looking over our group of costs we had capital costs; and these are those that I was complaining were too high for a lot of renewable technologies earlier.

We had O&M costs; program administration costs. I don't see fuel costs, but fuel costs are an issue for some of the technologies, either landfill gas, just pressurization and cleaning. Or if it's a biodiesel application, purchasing of the biodiesel.

And revenue loss for the utility is a perspective. You know, I'd mentioned earlier the Palo Alto analysis of well, I'm only willing to take a half a cent premium. Well, if customers put in generation behind the meter that will have an impact on rates. And so we estimated that in revenue loss perspective. It is in there. It is important to the municipals.

So then we've got all this list of

costs, we've got this list of benefits, how do we organize it. And what we did was take a look at four different perspectives, okay. And these are fairly traditional, but maybe slightly different than everybody's used to.

We looked at what they call the RIM test. This is the classic killer of energy efficiency. And it is really important to the municipals. It basically looks at, well, will my rates go up or down if I do this renewable distributed generator as a part of my supply portfolio.

We looked at the participant cost test. So if we're looking at behind the meter generation is it a cost effective application for that customer. Is their bill going to go down more than they had to pay for the unit.

We also looked at utility owned and directly connected renewable generation. And in that case the participant cost test would really be the utility cost test down here.

And we took what we call a total resource cost test, which is the sum of all of the direct costs and benefits that are flowing into and out of that community. So if I'm talking about Alameda and I draw a control volume around Alameda and count all dollars coming in and out, are the overall costs for energy higher or lower. So that's a slightly different interpretation of the total resource cost test and say in the California Standard Practice Manual for DSM, which would look at the whole state. We really focused on the community because that's what they wanted to know in terms of their decisionmaking.

So far all of this is just direct costs and benefits. And we're going to get to the indirect benefits and how that plays in.

Our approach was to calculate the net benefit, given our assessment of benefits and cost levels for different technologies from different perspectives.

So what happens when you do that. And this is an example of output. I think this is from SMUD. Should have labeled that. And what I've got here are the list of technologies, and I'm sure this is probably pretty small for most folks. But what I have here is a list of technologies that we looked at. Biogas, looking at fuel cells, microturbines, reciprocating engines, gassification, municipal solid waste, biodiesel, solar, wind.

We were really trying to be as inclusive as possible. For each technology we estimated -- and these results are benefit/cost ratios. We have a similar table that shows the net benefits. But the benefit/cost ratio from each of our cost test perspectives.

And then we made bold those that are greater than 1. A benefit/cost ratio greater than 1 means on a life cycle financial analysis the benefits outweigh the costs. They are larger. And those are potentially likely options.

Now, for this analysis we find that the, here is an 800 kW with combined heat and power. So this would be a reciprocating engine that gets waste heat recovery that's run on either landfill gas, biogas or some renewable fuel. That's an 800 kW version.

If you've got the available gas and waste heat usage, the 3 megawatt version is slightly more cost effective.

Going down the other one in bold here is, and I'm looking at the TRC test now, is the large scale wind. These don't get any of these distribution benefits that we're talking about because we've connected them to the transmission system. But those look cost effective with our assumptions of wholesale prices and so on.

Now, some of these are more, you know, closer to one than others. And depending on the perspective, some municipal utilities like Alameda look at this as more of a process. So, if they do an RFP or they get better information on cost and performance, they can go and take our tool, update that and they'll get a new value for their benefits and costs. So this is a way of basically finding those that have the most potential.

Now, that's the TRC test. The participant cost test is also important. On the benefit side of the equation there what we've got are reduced utility bills. So now the bogey, if you will, is not the wholesale market, what costs are changing for the utility, but what costs are changing for the customer. Their bills are going to go down if they generate their own energy onsite. And these cogen applications look well for that, as well.

The RIM test is well, what's my rate impact. Are my rates going to go up or down. And all of these will have a rate impact.

The utility cost test would be a utility owned type of installation like that. And really tough for the utility to find a renewable DG that competes with the wholesale market, with these sets of cost assumptions. We're going to look at the sensitivities here in a minute.

Another cut at this, and now rather than looking at all of the technologies, what this shows is the benefit/cost and net benefit for solar PV. And I just pulled one example to show how the analysis works for our four different cost tests.

And so what we've got here, and these are life cycle dollar/kW numbers, of benefits and costs for that type of resource in our four examples.

Each of these, for example this benefit here is the sum of a number of different components: wholesale energy, transmission rate savings and improved reliability. These other, and this is a result from SMUD, as well -- these other benefits could potentially occur, but didn't for solar PV. Those would have been distribution capacity savings, other direct benefits, and other non-municipal incentives that the utilities can bring in.

I don't want to go through all the benefits and all the costs here, but I think the point is multi-stakeholder analysis of life cycle benefits and costs.

Now, this is still all a static assumption. So far we've talked about all direct costs and benefits. And I wanted to talk about how we addressed the indirect cost/benefits. That's really important for looking at renewable resources. And it was something that people said in almost every meeting is, yeah, but cleaner air, community involvement, those other benefits we want to put in there. So how does that work.

Well, if, for example, the municipal perspective we line up the benefits and we subtract off the costs and we get some premium; maybe it's our 1 cent number, for a landfill gas application.

Now, we're not going to stop there and just say, well, 1 cent is the premium; it's better to just buy energy on the wholesale market, forget it, let's move on.

Let's look at what the indirect benefits are and compare. So, the approach we took for that is really to do a map of indirect benefits. What we started with was basically a literature survey of those cost and benefits -- those indirect benefits that people commonly talk about and then try to organize them by technology.

So, for example, okay, here's our renewable -- we're talking about renewable DG applications. There's a set of sort of general benefits for renewable energy. Emission reduction; feel-good value; fuel-related value; environmental value.

For each of those, emission reductions further we can decompose, reduce NOx, SOx, CO2, particulates. And you may have a longer list than that, even.

Feel-good value. Might be political capital; might be aesthetic value; might be -- can't read this one -- but, oh, aesthetic value, reduced power lines and equipment. Okay, if we can defer a distribution line or substation.

So we took from our literature survey a whole long laundry list. Now, with our application that we like, say it's the cogen with landfill gas that we were talking about earlier. I can go down and look at basically either, depending on the decisionmaker, check off those benefits that apply. I can quantify how much reduced NOx, SOx, CO2 in terms of tons or pounds of reduced emissions.

I can look at, through the whole list of those topics normally used for that, and compare with my premium. So we didn't try to add them together. We tried to really make a list so that people could do this assessment on their own in the decisionmaking process to purchase the resource.

On uncertainty analysis, I think I've said we wanted to make sure we didn't do this in sort of a static approach. We did our economic screening analysis withholding a number of variables uncertain.

Key uncertainty variables that we had, the DG output pattern. Particularly for renewables, you know, you've got this intermittency issue. You've got capacity factor of wind turbines; is it going to be high or low at this site. What's the reasonable range. We've gotten load forecasts which is a really critical driver for distribution capacity. Technology performance and heat rates; wholesale energy costs; transmission costs.

All those are really critical variables. The discussions in the state about locational marginal pricing is a really big deal for the Bay Area municipals because they are in a load pocket, as we saw on Ron's transmission map. There's a tough area, a switch to LMP may increase their costs of transmission, which in our model would translate to higher transmission costs and more value for in-area resources.

So how does that look. Going back to our 800 kW reciprocating engine with the waste heat, if we take and assess the range of value of wholesale market prices, transmission prices, distribution capacity savings, capital cost of the unit, fuel costs, capacity factors and we look at, well, here was our net benefit. We had a winner. Remember this was one of those page 1 that had a benefit/cost ratio greater than 1.

If our basecase was a life cycle benefit of $650 a kW approximately, what's the range for each of these variables. So, on our low market price forecast, what's the value going to be. On our high market price forecast, what's the value going to be.

If you look at transmission, the sort of collective wisdom of the Bay Area utilities is that, well, I'm right here right now. In terms of transmission I really only expect it to go up. Any disaggregation of transmission rates and tariffs may drive my prices up.

So, on the uncertainty range it's not symmetric here. It's well, if the value goes way up on transmission it'll be much more valuable to have an in-area resource.

Distribution capacity, and notice I got basically no range around this at all. And that's because my distribution capacity cost for this analysis -- this is the City of Palo Alto -- is basically zero. Shoot, what happened. I went in trying to find all these distribution capacity values. Well, right now for Palo Alto, and a number of other Bay Area munis, loads are really down. The economy hasn't come back and peak loads are not where they were in 2001.

So, in terms of distribution capacity, they already built their distribution capacity for a load level that's much higher than they're at right now. So that's a problem for them -- well, that's a problem for our analysis in times of finding more distribution capacity value, because they've already built the system.

And, of course, that's very location-specific, right. I'm talking about Palo Alto on this chart. SMUD does have distribution capacity cost value. Alameda and San Francisco, Alameda does not, San Francisco does. So two of our four case studies really do have distribution capacity value here. And it's because of our economy and where we're at in terms of load levels.

Capital costs, fuel costs, capacity factor from the range of reasonable costs basically are symmetric around our estimate. The key is that none of our variables for this type of application on their own pushed the life cycle benefits lower than zero. So that's what we were really trying to check, is do we get an answer change. Because remember, we still have a pro forma and other business cases to go through before the utility builds it. But do we have any major problem areas here.

You can reorganize that same information while also comparing the relative change in the overall lifecycle benefits of each component. So this is another way of looking at the same sensitivity chart. Here's my point. And then look at, well, capacity factor is going to raise, go from maybe $480 to $820 life cycle net benefit. The vertical axis is what we just saw.

The horizontal axis we also wanted to do. The horizontal axis is the percentage of change that that say capacity factor variation has relative to the total energy value of that resource. So the farther I go left to right the bigger the component is of this uncertainty to the overall project economics.

So, those that have a really, you know, far to the right, like this looks like transmission because it's that big asymmetrical line, is a pretty big issue. It stretches out pretty far. And that makes sense given that the potential for transmission costs are really -- there is a big potential for them to increase quite a bit based on the assessment of the utility or resource planners. Okay, enough of that.

Uncertainty. I wanted to show some of the engineering side and then talk about how it comes together. The engineering analysis started with developing a circuit model. Okay, so this is a load flow model of the distribution system. And that feeds into a renewable DG engineering screening analysis.

So, the screening analysis is, once I've got my circuit model, where are the best places on my system. How many losses am I going to save, how much capacity am I going to save. That also feeds into a reliability analysis. And I'll talk about how we did that.

I'm talking about it, of course, ElectroTech Concepts was our partner doing the engineering analysis. And they used ElectroTech's distribution system simulator. And I'll talk a little bit about why we chose that tool.

So what does the circuit model look like. Why do we develop it. What I have down here are four pictures. And these are the utility systems that we looked at in our case studies.

So, for example, here is -- this is a picture of Palo Alto from a distribution planner's point of view. Here's downtown; 101 comes right through here; 280 comes right through here. They have a really long feeder that goes up into the hill there, the Coastal Range behind Palo Alto and towards the ocean. So that's what this is coming way out. And then in red I've got, on this chart we've got the distribution substations modeled.

The interconnection point to the transmission system for Palo Alto is right here, I believe. And this dot right here is probably one of the points on Ron's transmission map. So, if you take one of the interconnection points on his map, which I think was -- I think the interconnection is, I think, is 130 or something, 138 kV, down to a 60 kV system. All this distribution system would connect up to that point. And I think later in the day we're going to talk about some integration. That's Palo Alto.

Here's a section of SMUD. Oh, and just to give you an idea, the total load here in Palo Alto is about 170 megawatts, something like that.

Here is an area in SMUD. The total load in this area is about 700 megawatts, so quite a bit larger. These little nexuses here are substations. I think there are about 20 or so in the area. We just took one piece of the SMUD system, what they call area B. I believe the river is right here, and this is the area that kind of goes out towards the airport from here.

Here's Alameda. Alameda is an island, and they serve both Alameda, the island, as well as Bay Farm, Bay Farm Island, which interestingly enough is not an island. Oakland Airport is right here.

And then in San Francisco we're doing more detail but on a smaller area. And this is the Hunter's Point Naval Shipyard, which is an area that's being looked at for redevelopment. And the question is how do they integrate renewable DG with the development.

So, all of these projects, or all of these municipals are in a slightly different position. The resources are different for SMUD obviously than the Bay Area utilities. And our engineering analysis kind of gets at those differences and we'll take a look.

Once we've got the circuit models put together, one purpose is to be able to look at what are the best locations. So, for example, this is the output. We asked the model what's the best place to put in our area 13.5 megawatts of distributed generation sited for capacity.

So, if you tell it, well, I want 13.5 on our system, where are the best places, it will go in, and these yellow circles are generators that it puts on. If you sum up the capacity of all the generators you get 13.5 megawatts.

So what it can do is go through and look at the load flow and decide where's the best place for capacity.

The other thing we screened for that distribution engineers will bring up almost immediately when you start talking about distributed generation is how is it going to affect my system.

And we did two screens for that on our analysis. One is a voltage regulation screen. So if I have the generator immediately turn off what's going to happen to my voltage on that distribution feeder. Is it going to go too low, because loads are going to pull it down. If I have the generator come on, what is that going to do to the voltage. And then over-current protection.

So, again, am I going to have too much in-rush current to have an operational problem when I have my generator on or off. And so we took a look at that and incorporated it into our siting decisions. Because, again, we want to find applications that will work. So we want areas that will pass these voltage and current strains which are part of the standard interconnection process.

What we've got here is that same map -- this is SMUD now -- of their system. And we shaded it differently, areas that have, and this is the current example, where we've got greater changes in the lines for generation.

Now, I mentioned before, most every utility planner that we talked about, they're really concerned with reliability. And so we did quite a bit of work on trying to address that.

The basic approach that we used is shown in this diagram. And one reason why we used the ElectroTech model of analysis is that we didn't think that you'd get at the reliability analysis by doing the traditional capacity expansion planning approach for distribution -- which is to take the peak hour of the year and run basically a snapshot of what the loads look like on the system.

What we did instead was for the whole year, and this is just one day as an example, but we did the whole year's load curve, what are the loads at each point along the way. So rather than one snapshot we've got the whole year.

And then we started to count some things. The first thing we counted was the energy exceeding normal. So we defined a rating on the distribution line that we called normal. And we computed -- we summed up all the energy over that normal line that was being served in the basecase. And then we would put on the distributed generator and re-run the tally and find out how much we had improved our energy exceeding normal.

We defined the normal limit slightly different depending on each distribution utility's comfort level, but typically around 50 percent of the loading of that line. We chose 50 percent because with 50 percent the idea was if you have a contingency, then through one switching operation you'll be able to pick up all the load again.

So the normal rating is sort of a threshold for when you're at higher risk for having outages. With your distributed generator you can prevent yourself from going over normal. If I had a generator that had an output that cut off this blue area exactly, then I would be in a more favorable reliability position.

We also counted unserved energy, which is energy over some maximum emergency rating.

This is the point where you actually start shedding load, you start turning customers off in order to protect your system.

As I had mentioned, loads are down right now. We pushed all the systems out ten years and didn't really get much unserved energy. Of course, if the economy rebounds faster than we think, something like that, it could change.

So, given our approach, these are the kind of results you get. And this is still going back to that 13.5 megawatt example.

What I've got here is in this darker line the basecase. And here we've got our megawatt hours of energy exceeding normal in that area. And then I've got a load here for that area.

So in our basecase say we've got 50,000 megawatt hours of energy exceeding normal. If I put my 13.5 megawatts of DG on the system, I improve the reliability situation in terms of energy exceeding normal. And I jump down to this little brighter magenta line.

So what I've got here is this gap and I've written or shown this difference over here, okay, so this red line. So, what we're seeing is if you go and you establish a reliability level like I'm currently at 50,000. Then I jump down and I put my DG in. I get a -- I can increase the load in my system by say 10 megawatts in order to get back to the same reliability level.

In other words, my peak load can grow by 10 megawatts if I have that 13.5 megawatts on my system and be back to the same reliability criteria.

At these low load levels I'm getting about 15 megawatts for my 13.5 megawatts of generation. So I'm actually multiplying up. As I get this area loaded more heavily, then the contribution and the ability for the 13.5 megawatts to provide value goes down to something less than 13.5 megawatts. And this is, again, putting the generation at the best location for capacity.

So, that's the reliability piece. What about the load and resource analysis piece. And I wanted to show a few more examples and talk about the feedback.

We didn't stop with the 13.5 megawatts of DG, we did a number of different cases. One case we did is well, what if we do just a ton of photovoltaics in this area. By a ton we meant 20 megawatts. So we're going to put 20 megawatts in; find the best places; and well, here's where you get. So this is like PV on lots of rooftops in northern Sacramento.

Then what we did is line up -- and the process that we used here for PV we did a similar approach for peaking reciprocal engine, output patterns, baseload output patterns, but PV is, we thought, probably the most interesting example.

If I show the load shape for the area, and I've normalized it, so we can put them on the same chart, this is basically the cyclical daily pattern of load shape on SMUD's system. And this is just a weak snapshot, but again, we did a year.

And then I've overlaid with PV output shape. So by a comparison you start to get this idea of well how coincident is it. Am I going to start saving capacity by putting PV on rooftops in this area.

And what you find out is well, you do okay, but you don't do fantastic. This PV is really peaking about three or four hours before my area is peaking. And this is actual PV data and actual load data. So we know pretty well that, yeah, our peak loads occur in the sort of 4:00 to 5:00 p.m. area, and our PV output peaks in the sort of 1:00 to 2:00 p.m. timeframe.

How does that coincidence factor translate to the rest of our analysis. We can do a similar chart that we had looked at before for EEN. Okay, here's our 20 megawatt example. And we've again estimated, in terms of our reliability, how much of that energy exceeding normal have we reduced.

And for 20 megawatts of PV we get something on the order of about 8 megawatts of peak capacity relief. In other words, the area's load can go up by 8 megawatts and we'd be back to the same reliability level we were. So that's how we measured it.

Now, does 8 megawatts in 20 sound high, low? It's pretty decent, actually. Compared to the Bay Area utilities, which would have a number around 1 or 2 for Palo Alto and zero for San Francisco and Alameda, the capacity benefits of PV are reasonably high in this area. Something on the order of 45 percent of the rated.

So we've looked at a few examples, and we've pulled examples of each aspect of our analysis from the four case studies. In conclusion I think we're pretty satisfied that we've developed economic tools for screening so that we can find applications that are the most cost effective.

We think that we've perfected or getting there, in terms of the local engineering tools, in terms of distribution evaluation tools for the distribution system, so we should be able to get the DG in the right place, and quantify what its value is.

In terms of short-term success, we've got these four case studies. I'm hoping that some of them turn into real projects. I think our long-term success is really still a question mark. We want to find renewable DG applications that get built. And so far we haven't. We've done case studies; we've got interest; and we're sort of moving in that direction. But I think ultimately that's the question mark and that's where we're headed towards hopefully.

That's the presentation. Are we going to do questions at the end? All right, thank you very much.

MR. SIMONS: We're going to shift now

and have Hank Zaininger come and talk to us about the case study down in the Chino Basin.

Again, just a little background. Chino has a lot of solar resources, a lot of biogas potential because of the large number of dairy cattle down there.

I understand also that SCE -- this is, if you compare this to the EEE study, which was largely municipal utilities, this is down in the SCE territory. And I understand that SCE might, in fact, be pursuing some of these results.

So, Hank.

MR. ZAININGER: Thanks. Today I'm going to talk about the minigrid case study. And the overview of the presentation is we're going to look at the minigrid project approach; we'll look at the minigrid model development; we'll present the expected biogas building integrated photovoltaic penetration scenarios.

Then we'll go through the minigrid project results including local T&D impacts and potential T&D value.

Before we get into it, I want to mention, this work is part of a Commonwealth PIER renewable energy program. It's part of what is called task 1.1. A lot of the results that I'll be talking about today in the minigrid study are in task reports in task 1.1.6, 1.1.9. And there are some results in 1.1.10.

I'm with ZECO and I'm part of this team, consisting of Commonwealth Energy, ITRON, CH2M HILL, REDI and we did the power flow analysis.

The results are available for the tasks that are done. You can look on the web and find these results in much detail. What I'm going through today is just an overview of what we did as part of that project.

First, the study scope -- now, we're going to talk about a small, relatively small area in the Chino Basin. It's part of the Southern California Edison service area. And if you look at 12 miles by 11 miles, this is kind of the area.

The renewables, we looked at eventually renewables like, I guess that's why it was selected for the study because there's a lot of different kinds of renewables potentially that can developed in this area.

In this study we looked at the nonresidential building integrated photovoltaics. We looked at dairy waste and wastewater biogas projects. And we also looked, there was one landfill bioreactor site that we also looked at in this small little area.

Then this study, what we looked at is the scope, we looked at expected high and low penetration levels for renewables in the years 2007 and 2012. This project started in 2002 so we expanded out about say five years and then ten years and looked at what the potential penetration levels might be based on market evaluation.

What we did in this study is we performed a power flow analysis to determine the local T&D impacts and the value.

Now, let's talk about data collection and model development. First, this area kind of evolved as we did this study. So the final area was the 12 miles by 11 miles. And, again, this is in the Southern California Edison service area.

And I have to say we had really close cooperation with Southern California Edison in gathering all the data for this study. We obtained a lot of proprietary information from them in order to do this work. And included like substation data, the 66 to 12 kV. By the way, they use 66 kV in that area rather than 69 kV. So we used their terminology. And 12 kV substations. And the 12 kV feeder data, circuit maps. We got conductor sizes, ratings. And we also got projected peak loads at the substations, and at the various feeder positions, at the substations, for year 2003.

So we collected all this. We then developed representative electrical parameters for performing this power flow study. And we used publicly available sources for the various conductor sizes and things like that, that were available.

And we used all this information and we just physically laid out the minigrid electrical database using the circuit maps showing all this information, as well as street maps to get where they were and the various streets and all that sort of thing. So it was a pretty comprehensive study.

There was several hundred nodes that were developed in this thing, and it's significantly large detailed representation of this little area.

We then obtained, local 66 gave me subtransmission information, electrical data. And we added that to the minigrid. And inserted this information into a bulk transmission power flow model.

And by the way, once we inserted this into -- to put it in perspective, the transmission model, the bulk transmission model, there were three substations that all this plugged in; like 500 load points, 300 generation points and stuff like that, were plugged into three substations. They're Etiwanda, Mira Loma and Chino. So this replaced three substations in the bulk transmission model.

For this study we used the General Electric PS -- program. This is the standard model used in WECC for transmission studies, for power flow studies and dynamic studies. And it's widely used. We felt that this would be a good choice. I'm familiar with it and used it for a number of years. It's also used extensively for dynamic system analysis throughout WECC. And it also has short-circuit capability, as well. So we felt that by using this that the results of this study could easily be used for future work.

Now, where is this place. Right, this is the route 15 going south; and this is route 10.

And here's like Ontario Airport. And so this is the outline of the minigrid that evolved through all this work here. It's in the Chino Basin. So this is Ontario, this is Chino. This down here at the bottom is outskirts of Corona.

So this is the minigrid. These outlines here kind of show the service areas of various substations which we'll get to in a minute.

Basically the northern part of this is largely, there's a lot of commercial development and some residential. And the lower end there's a lot of dairy farms. And it's kind of, I'll call it rural because there's rural and then there's -- this is rural. You look, dairy farm, dairy farm, dairy farm, subdivision, dairy farm, dairy farm, you know. It's kind of like rural, but rural means different things in different parts of the U.S. than this.

All right, an overview of the system, what evolved here, this is like a drawing of the system. There are -- basically this is substation A. It has ten 12 kV feeders. All of the feeders serve this portion of the minigrid, okay.

There's a substation B, has 12 feeders. These 12 feeders serve this portion of the minigrid. And so on. Here's substation C, D. That was the first iteration. Then E, F and G were added in the second iteration. And as a final iteration, we added parts of two other distribution systems.

Now, these are all separate distribution systems, I want to point out. So there's what we call sub-I that has 13 12 kV feeders, but three of the feeders are serving this part of the minigrid. The rest of this distribution substation serves outside the minigrid. And over here is another distribution substation. There's a couple feeders that are serving portions of the minigrid and the rest is outside.

Let's go over to the model. So this model has nine 66 to 12 kV substations. There's a total of 72 12 kV feeders in this model. And to put the size in perspective, the projected 2003 peak loads information were about 565 mva. Edison's policy is to -- practices are to correct power factor to their unit to get the substation, so that also when I say megawatts or megavar, mva's are going to be relatively close.

But this 565 mva is, there's like 3000 utilities in the United States; 2000 of the utilities are smaller than this. So that's one way to put it in perspective. The other thing, since this is California, this is more than 1 percent of California. Okay, the load, the peak load.

So we kind of give this minigrid a nickname; we call it the money grid. Okay, so just to put it in perspective.

Well, then what we did as far as developing the model, we expanded the model out to 2007 assuming 3 percent per year load escalation; and then 2007 to 2012 at 1.7 percent per year load growth. These load growth rates were based on Energy Commission load forecasts for this area.

We then expanded the system as appropriate, adding transformer and feeder capacity as needed, to serve these load increases from the existing system that we laid out.

Now, I played like a distribution planner in expanding this system. And that, the synonymous with that is cheap. So what I did, as feeders became loaded, I rolled loads to adjacent feeders and et cetera, as best I could to try to minimize the capacity additions required. Because that's the way Edison planners would do it.

And we added enough transformer and capacity to serve the peak load. So I did it similar to the way that Edison distribution planners would expand the system.

And by the way, 2012 is a long time out for distribution planners. This 2007 is probably as far as they may be looking out that far. You look out the next five years. They probably aren't looking that far out for distribution planning, so that's a very long way out for them.

Then what we did is we determined an appropriate light load case. Really what we were trying to look at is when we put distributed generation in there, I was looking for a potential reverse power flow or backfeed into the system.

So we wanted to look at this, examine this as part of the study, so we then developed an appropriate light load case.

PRESIDING MEMBER GEESMAN: I want to make certain I understood what you said about five years.

MR. ZAININGER: Okay.

PRESIDING MEMBER GEESMAN: Do you characterize that as a pretty long horizon for distribution planning?

MR. ZAININGER: For distribution planners that's a long time.

PRESIDING MEMBER GEESMAN: What would you say is a more typical planning horizon on the distribution system?

MR. ZAININGER: I would say there are things within the next couple years.

PRESIDING MEMBER GEESMAN: Okay.

MR. ZAININGER: But generally they -- I can't speak for Edison, they have to speak for their planning. But generally you might look out five years, and that's your horizon study. And you're looking at what you're doing out that far. You wouldn't probably look out past that --

PRESIDING MEMBER GEESMAN: Right.

MR. ZAININGER: -- at this time. So, ten years is a long time for that.

PRESIDING MEMBER GEESMAN: Sure.

MR. ZAININGER: Now, transmission planning, maybe, you know, it's a little different than transmission planning. But remember, there are things happen, you know. They put a subdivision in; everything changes. Things happen quickly at this level here.

So, in any case, what we did is

expanding the system. These are the transformer additions that were needed. When we expanded out to 2007 the pink color looking distribution systems required transformer additions.

For this study we used one of their standard transformers, a 28 mva transformer. So that was added to meet the load growth out to 2007.

And so that, if you look at substations A, B, E and I needed transformer capacity by 2007. By 2012, you can look at, let's see, B, C -- I'm sorry, C, D, G and U also required transformer additions to serve the load increases out in the second five-year period there.

Notice that I colored -- the whole area there is colored, okay, for those transformer additions, which kind of, again for later, is if you had renewable generation, distributed generation installed in those areas, anywhere in those areas, that has the potential to defer the transformer additions.

Feeder additions. It turns out that we added in 2007 I think we -- it turns out we added a couple feeders into distribution system E. We added a feeder into distribution system G, and added a feeder into distribution system I. In 2012 we had to add two feeders into distribution system A.

Now, notice that this shading here does not cover the whole service area of the distribution system. Now, what that really means, to keep in mind for later, is if the distributed generation is located in the shaded area then it has the potential to defer the feeder additions. If it's located outside there, but still in that distribution system service area it does not, it cannot defer the feeder additions.

So, location specific or site specific. These impacts are location specific and site specific. And from now on I'm going to say that every five minutes. If I forget, you keep it in mind. Okay?

Now, what were the penetration scenarios. These were based on studies by ITRON and work done by CH2M HILL and the other partners. They developed market penetration scenarios and they put a significant level of effort as to what they thought would be installed by like 2007 and 2012.

So, 2007 they expected they would get

about 10 megawatts penetration. That was the expected value. Of that about 6 megawatts is biogas and about 4 megawatts of building integrated photovoltaics.

By 2012 they expected up close to 28 megawatts of penetration. And notice by this time they're getting a lot more, almost close to 20 megawatts of that is expected to be photovoltaics; and then the biogas is about 8.

Now, the high penetration scenario, if you look, you get about three times the expected penetration in 2007, and about twice the expected penetration by 2012.

The low penetration, okay, not very exciting. Okay. But it's low. Now to put that in perspective with the minigrid peak load by that time, you can see that the penetration, even in the highest penetration scenario, is less than 10 percent penetration of the peak load of the area. So we would call that low penetration on a minigrid basis. Is what the expected level is.

And now just to enunciate further, the biogas, we found there was five different locations for biogas in this minigrid area; four of them for wastewater or processing dairy waste.

The other one was a landfill bioreactor site that was in there.

The photovoltaics were distributed throughout the minigrid area by zip code. They did a study by zip code in places where there was a lot of commercial development and stuff like that. It was allocated based on zip codes. So it was distributed throughout the minigrid area.

Now, what is the performance of these distributed generators. All right, so if you look at this, I played an economist game here, didn't put a scale down there. Sorry. I'm an engineer. Normally I would have a scale there.

This is 24 hours; it's on a daily basis. These are like seasonal output for the biogas technologies assumed in the study. This axis is the rating in per unit. So basically for these, for 24 hours a day they're expected to produce at or near full output. As long as those cows be doing their job, we got biogas, right. So think of that. So that's the performance on these.

So throughout the year they're expected to run at or near full output. So for this study we assumed full output at the peak and light load conditions. We also ran a sensitivity case where we reduced the output 10 percent to account for potential forced outage of the equipment in the minigrid. So we ran two different cases there.

Now, the photovoltaics looks a little different here. The sun, you know, comes up during the day, goes down at night, so you don't get your 24 hours. And I actually remembered to put the hours of the day on that one.

In the summer, this is the curve there; here's your spring, fall curve and in the winter. So you get less; the insolation varies throughout the year, so you get different output.

Notice that the peak output, the maximum occurs at midday time. And that gets up to about 93 percent, that's the maximum output you could expect for the photovoltaics during the peak season. Now, every time -- I've done a lot of renewables assessments, and every time for photovoltaics they're rated at different conditions than occur during the summer peaks for a utility system. So generally they're always going to have to be derated.

So, we did. However, there is good correlation. This happens to be a plot of the daily load shape for the Edison system. And notice that the peak load for this system occurs during the midday hours.

The previous speaker had a presentation for SMUD where the peak load was occurring around 5:00 in the afternoon and there wasn't good correlation. This has good correlation on this Edison system. So what do we say, location specific, site specific, right, and utility specific.

So in the winter however you're down to about 63 percent. And in the spring/fall you get up to about 80 percent during the midday hours.

So what we wanted for a light load case is we were looking for reverse power flows. So we selected a light load case which was representative of expected weekend days in the spring/fall. And as a matter of fact, they're about 50 percent of the peak is a weekend day load at midday in the spring/fall and in the winter season.

We then derated the photovoltaics down to about 80 percent and used that for the light load case. Now, in the sensitivity case we took the derated values and also reduced them 10 percent for the sensitivity case to account for outages of the solar, as well.

All right, distribution system impacts. Now, again, since I haven't said site specific or location specific for five minutes, they're site specific and location specific. You don't plug and play. You've heard some people talk about plug and play. That doesn't really apply to distribution system impacts.

Now, the impacts to the power flow study that we looked at, were power flow reductions mainly at the peak. The game in the distribution planning area is you have to have enough facilities to serve the peak loads in the year. So this is the main thing.

So we were looking at potential power flow reduction with the renewables added at the time of the annual peak.

The loss reduction, we also looked at potential loss reduction with renewables added in there. We looked at voltage regulation, because that could be an issue that's going to impact voltage regulation requirements on a distribution system when you add the distributed generation in there.

Reliability. Now the reliability

measure, really to maintain the reliability with renewables in there is a key issue that has to be resolved. The utility has to be convinced that the renewables are going to be running during the peak.

But the game is basically reliability is the first thing, is to reduce peak, and possibly defer transformer additions or feeder additions, as we saw in the previous slide.

Other measures of reliability, which are used nowadays are evolving as customer minutes of outage. So that might be a criteria to add new distribution facilities, as well.

We also looked to flicker. That's light flicker. The light flickers, we looked at potential impacts when the distributed generation turns on and off.

And finally, reverse power flow. I wanted to look at reverse power flow because that's going to have impacts on -- that can cause voltage regulation problems. It will cause some of the voltage control equipment to operate improperly. And it can have impacts on the relay requirements to relay the distribution system with distributed generation installed.

All right, there's three other items here. Stability, short circuit duty, and relay. These are generally part of the next step of distribution system impacts. And these are -- the last two would commonly be done, but stability is kind of a new thing. It's not done that often.

Where we get down to next steps, I think for distributed generation this also has to be added as an important concept for the next step, which would be the interconnection study or detailed facility study.

All right, transmission system impacts. You know, the distributed generation, if you think bottom-up, the impacts are bottom up. Distributed generation can have impacts on the distribution system. They also can have impacts on the transmission system.

Now, things are different, reliability is different in a transmission system. So these are separate kinds of studies. The transmission systems or network systems, you heard contingency analysis, commonly there's other kinds of analyses done with power flow like post-- voltage deviation calculations, reactive margin calculations, things like that all make up the reliability of the transmission system. And they're different than the distribution system.

However, I haven't said location specific for five minutes. So they are still, again, location specific. The distributed generation has to be in the right location to have the potential benefits.

Losses in voltage, stability, these are commonly all parts of the transmission system impacts.

Now, to really quantify you need large DG penetration, if you're going to quantify these kinds of benefits. For the minigrid that we're talking about here, you need a bunch of minigrids. You need a bunch of them if you're going to quantify benefits on the transmission system.

Now, for the penetration levels we had in the study we had difficulty quantifying transmission benefits for the work that we did in this study.

Now, let's talk about power flow reduction, now, at the peak. So how do we do the peak loads. Well, these are the various distribution systems. Remember we put transformers at A, B, E and I. Okay, these are the ratings of the transformers with the new transformers added. Here are the flows in there during peak without distributed generation scenarios installed. For the expected scenario here are the peak reductions, and here's the high penetration scenario with the peak reductions. And the low scenario peak reductions.

Now, the first thing that catches your mind is the biggest number here is at F. Well, the Murphy's Law of renewables assessments or distributed generation, this one is not heavily loaded, the transformer, doesn't need a new transformer.

So although you have a large mva reduction, you don't get the benefit. It's in the wrong spot, right? Now some of these others are also pretty low. This one here is not too bad. However, D also didn't need a new transformer. So, this kind of shows the location specific part of the problem.

Now, the other thing is well, what does this mean if you look at these numbers, the mva ratings, now the load has grown at 3 percent. Now, just to put it in perspective, if you're going to defer something here you need to have 3 percent of what these peak loads are if you're going to defer something here. Right? That's a rule of thumb.

Now, let's look at 2012. Well, things are looking up here if you look at the expected mva reductions. They're higher in the expected case. In the high scenario they're significantly higher. The low still not very exciting.

But now here we had the transformers required at C, D, G and U. So if you look at these situations here now you have the potential to defer some of these transformer additions. There's enough mva reductions to reduce these flows in the expected scenario and in the high penetration scenario there's even more potential.

Oh, the other thing, I point out that the load growth is 1.7 percent. The other thing going in your favor here was that load growing at 1.7 percent per year, if you're going to defer something a year, you only need to have a 1 percent reduction, right. Or, I'm sorry, 1.7 percent reduction rather than the 3 percent that you needed earlier with the higher load growth rate.

So, loss reductions. We did calculate

loss reductions. There were loss reductions in the minigrid during peak and light loading conditions with the distributed generation installed.

However, the penetration is relatively low. And since we did essentially two points of generation and load points in the -- throughout the year, we didn't -- you don't really have to do the whole year, but if you're going to look at losses throughout the year, you have to quantify, you really need to look at more points than what we have here.

But just based on my experience with this low penetration, the losses are -- could probably be significant, but they aren't going to be exceptional or anything with this low penetration. If you had higher penetration you really need to take a closer look.

Flicker. I'll just briefly explain what I mean by flicker. These curves here, there's two curves. It's light flicker, like I said before, there's perception. And this axis here is voltage drop or voltage fluctuation. This here is frequency of occurrence.

So over the decades sometimes these

curves have been referred to as GE curves. That probably was made up by GE. I used to work for PTI; maybe we called it PTI curves. But these kinds of curves have been around, pretty commonly used.

For example, if you have a small voltage fluctuation you can't see it if you're sitting here. If you have a larger voltage fluctuation you might be able to see it, but you aren't supposed to be irritated unless it's larger up to this area here where you start getting irritated.

Now, at a smaller level, which you could be irritated at this level if the event occurs very frequently. So to put it in perspective, these are kind of a nonartist rendition of these curves. But on a minute-to-minute basis, if you have these fluctuations you can tolerate up to about 2 percent before you irritate people.

And this is where the utility -- if you get above this irritation curve the utility will want to do something about it. Because they don't want to irritate the customers, because they pay the money, bring the revenue in, right.

And if it occurs very infrequently, like an hour or less frequent, then you can tolerate up to about 5 percent, is what these curves show. This varies from utility to utility. I've seen some utilities maybe chop it off at 4 percent or whatever. But for this case, about 5 percent.

In this study we looked at worst case voltage fluctuations. We were getting less than 3 percent. And for these kinds of renewables that we were studying in this study, the frequency is supposed to be -- it should be very infrequent switching observed for these kinds of technologies.

Now, if you were talking about wind, that would be another story.

All right, one-line diagrams, reverse power flow. There were a number of instances of reverse power flow in this study. And this, what I said before, it's a low penetration is what we were studying. However, in this particular -- this is a feeder and I'll explain it. This feeder actually has pretty high penetration on it.

So here's the substation here; this is a one line. Here's the feeder goes along here. It branches off and goes over here and here. These circles here, the ones are the photovoltaic generators, and here's a large biogas generator.

And this particular feeder, I believe that was RP-1. And under light loading conditions these things show this flows, reverse power flows into the substation.

The normal way without generation in a distribution system is the power's flowing out. Now, the first thing that comes to mind to identify from this is this number right here, this 1.033. Edison has a tight voltage spread that they have to maintain. It's required in the state. And so they basically have to maintain at the customer 1.0 to .95, 5 percent tolerance.

Now, when you look at the feeder level here you have laterals; you have secondaries. Generally you assume maybe 2 or 3 percent drop. This is above the 3 percent. This indicates that there are potential -- there is potential for voltage regulation problems with the large penetration. And this is large penetration, it's over 5 megawatts. And that is a large penetration, by the way, on one individual feeder, 5, 6, that's a lot. Two or 3 I used to think was a lot ten years ago.

This, I believe, can be tolerated; however, there's going to have to be voltage control coordination so that the voltage is maintained for the customers on this distribution system.

And this is different than if you have your own collector system, you're in a wind farm and you aren't serving customers. You don't have to maintain the same kind of voltage that they do. But customers have to have voltage spread.

Now, the second thing that always comes up with reverse power flow is they talk about LTC transformers. If the power -- or voltage regulator is out in the feeders, if the power flows in the reverse method it can cause problems for the control. They may boost when they're supposed to buck, and you've heard that, people say that for years.

However, Edison in the minigrid area doesn't use LTC transformers, and they don't use voltage regulators. So, that's not a problem. However, that is solvable for utilities that have that. You have to have bidirectional controls to these devices. So it's no show-stopper or anything like that.

The final thing is relaying. This can have a significant impact on a relaying schemes required for a distribution system. So that's an important thing that has to be studied when you have penetration levels high enough. Even in this low penetration case, it's going to impact the relaying requirements and it needs to be studied in detail.

All right, let's get into a few numbers here. Enough of this stuff. There's three questions I'd like to ask when we talk about cost benefits analysis.

The first thing is who gets the benefit; who gets the cost; and who pays the benefit. Now, maybe that third one might be important, that the benefit actually gets paid, right.

Now, today, I think still today, generation services on the Edison system are competitive; due to deregulation I understand there's an AB-206 which might make things vertically integrated, but at the time these kinds of services, if you're going to evaluate the value it has to be done on a price base method.

T&D services still are regulated, so they'll be done on revenue requirements, the present worth of revenue requirements basis.

And, again, I want to say, since I

haven't said it that the benefits for the T&D are site specific and utility specific.

And so with that in mind let's just look at some of the numbers here. To expand the system, these are the capital investments that we had to install.

Now, from Edison last year I obtained in 2003 dollars I got some cost estimates for these kinds of facilities. Well, what does it cost to install a 28 mva transformer. Well, that costs somewhere between $600 and a million dollars -- $600,000 and a million dollars in 2003.

And underground feeder, that can cost anywhere between $400,000 a mile and $650,000 a mile. And an overhead feeder can cost anywhere from $150,000 a mile to $300,000 a mile.

Based on that, these are the expansions. We escalated things out at 3 percent, assuming 3 percent out to 2007. This adds up to over $14 million is what it costs to expand this minigrid.

This annual fixed charge rate, assuming a 15 percent fixed charge rate, this is the annual value. In 2012, you keep escalating at 3 percent, you still have over $12 million of capital investments. And these have a potential to be deferred.

Now, we did the analysis and we looked at deferring these feeders and things like that. If you looked in the -- there wasn't too much opportunity here in 2007 except for the high penetration scenario. And you get benefits up to about a million dollars of present worth of revenue requirements.

In 2012 you get benefits for the expected case of about $2 million up to about $4 million for the high penetration scenario. And the basis for that is deferring the capital investments -- well, in this case, several of them can be deferred several years. This one was deferring some feeders and transformer one year. This was a couple years. And this was some multiple-year deferrals.

The things were discounted at -- I didn't give you that, the discount rate was 10 percent that I assumed for these numbers.

To put it in perspective here, these are the penetration levels that are associated with these revenue requirements.

Now, let's be smart about where we put them. We put them in different locations. Some of the places didn't get any benefits. Some of them have higher benefits. So if you remember back on that slide the substation E transformer addition, if you deferred that you could get a benefit of $130 a kilowatt is what it translates to in 2007 dollars.

Now, if you're also located in the portion of sub E where those feeder additions, remember that shaded part of the feeder addition slide. And there was an even larger benefit there that would be also available to you. So, DG installed in this area has a high potential of distribution credit or value, okay, or benefit.

And here's some of the other numbers here at some of the other substations. And here's benefits in 2012. The larger one is over in distribution system A, the feeders there. That there was a large potential benefit if you could defer those two feeder additions there.

Now, --

PRESIDING MEMBER GEESMAN: Let me ask you, Hank, before you go on. With a 15 percent fixed charge rate, and what I think was a 3 percent inflation rate or escalation --

MR. ZAININGER: Yeah, escalation rate.

PRESIDING MEMBER GEESMAN: -- rate, how did you choose a 10 percent discount rate?

MR. ZAININGER: I just picked it out of the air. It's similar to what I've used in the past. I did not make any detailed study.

PRESIDING MEMBER GEESMAN: Fair enough.

MR. ZAININGER: I just made assumptions that were half way reasonable just for illustration.

Now, a couple things we need to say. First of all, we did this study, there were no show-stoppers that we found that would shock, that would stop these penetration of these renewables.

However, we also have to say that these benefits, these numbers that we saw, they're potential benefits. They are not automatically going to be obtained. They have to be earned, okay. And they have to be earned by the utility having confidence that those distributed generation devices are going to be operating at the peak. They have to have confidence, the confidence to use that rather than add the facility, the new distribution facilities.

Now, in order to get that confidence and insure that these things can obtain these benefits, the next step is you have to really do a detailed interconnection study.

Now what you really want to do if you're going to do it, is you want to look at relatively high DG penetration. Now, DG penetration means different things to different people. At that one feeder we had high DG penetration. We had low penetration for the minigrid. We had negligible penetration at the transmission level.

But high DG penetration at the distribution level. You do a detailed interconnection study. Because to get confidence as to performance of these renewable distributed generation, you have to have confidence that they're going to be there for you, just like you put in a feeder, that thing is there. It's going to be there and it's going to serve the load.

And if you do a good job, and I think Edison, by the way, does a good job in planning their system, that it's going to be there. If something's wrong they've provided for that.

Now, so you want to maintain that. So, first of all, you have to look at relaying requirements. What happens, all right, if there's disturbance. What do you do for reclosing. How do you detect the fall. What do you do with the distributed generation on your distribution system.

Now, the integrated voltage control, I briefly mentioned that before. That is something you have to integrate, the distributed generation, into your system, and make sure you control the voltage so you supply the proper voltage to the customers.

Now, one of the -- if I spelled scheduling right, yeah, okay -- one of the things is reactive power scheduling for when you have large penetration. That's one of the things I thought. If you can schedule the vars and make sure that they're changing their vars or power factor or whatever they want to use, that they can control the voltage that way with the generator. If they can't, they may have to, under some conditions, shut down some of the generation, have to take it off.

So this is one way without reducing the output of the distributed generation. And I think probably it will work.

The other thing is short circuit duty impacts. This is a -- grid that we are looking at here, 20,000 amp short circuit duties are common versus 10,000 for the standard utility. We have to check this and make sure that they're going to fit in with this, so the breakers can clear the fault if there is one.

So these are important things. The other thing is the dynamic study. You need to look at the transient response of these distributed generators to nearby disturbances. And basically they need to be able to -- the main thing is they need to be able to ride through faults that are, say, in adjacent feeders and you get a voltage dip, if you have photovoltaics, the voltage dips and it trips off. Well, if this is during a peak time and the utility system is counting on that to be online so that you don't overload that feeder, you have to figure out some way to make sure it stays online.

So you need to look at the voltage; the swings. And if you have a rotary generator you want to make sure it doesn't go out of step. So you need to check this and insure that these, or at least have some kind of control response so that you are prepared, so that they're going to stay online when they're supposed to.

Well, that basically summarizes this study. If you have any questions I'll be happy to take them.

MR. SIMONS: We are going to take a break. Before we do that, though, I just wanted to kind of set this up.

The DG studies, if you look at this, one of the lessons is that it's kind of like an analogy to compact fluorescent bulbs. You get a small increment of benefit for each compact fluorescent. And as Hank mentioned, and as Snuller referred to, you've got to have a lot of these things to make a big impact on the grid.

And this is renewables transmission planning. And so when we start looking at, okay, well, then how do we really begin to capture these benefits, then we've got to aggregate them.

And so we're going to take a break, but when we come back Ron Davis is going to talk about how we begin looking at the various types of tools analyses to aggregate DG, to see if, in fact, we can have an impact.

And one of the things Ron's going to be specifically looking at is PV. Because, again, we've heard discussion about a million solar roofs initiative. So you begin to look at something like that, is there, in fact, a quantifiable impact on the system.

And I suggest since it's about 2:55, we're going to plan on a 15-minute break, and we come back at around 3:10.

(Brief recess.)

MR. DAVIS: What I want to talk about now is this morning we talked about bulk renewables and looking at how it can improve the transmission system by looking at wind and geothermal.

And one of the areas that we had talked about this morning we really wanted to look at was starting to look at residential solar and commercial solar, and looking at biomass on a DG level.

And so one of the areas that we're going to do this afternoon, that I'm going to talk a little bit about is some case studies that we ran. Because one of the things that we wanted to do and is part of our project was we're looking at the transmission system, and should we be going and having some test cases where we look at the distribution and we model the distribution area for a certain utility, or limited area, like you heard this morning, and try to model that. And then model it up through the transmission system.

But has the work been adequately done, and the work that was done previous to, like the previous speakers, are they good that I could just take their megawatts and not duplicate their work efforts that they have done in modeling a distribution system. Let's say, take them to the low side of our transformer for the transmission system and then model their benefit on the high side.

And so that was what our intention to do on part of our project, is model the distribution system and what we would install there. And then model it up through the transmission system and look at this contingency overload benefit.

A lot of the work has already been done. Can I take theirs on the aggregated megawatts and then model that and look at its benefit. So that's one of the things we're still working with.

But what I want to do is look at two case studies real quickly. And the other thing is right now we're working with the Commission and working with CDF and they're doing these mappings that we had done this morning where they give us the growth and the technical potential. And then they tell us where the hot spots are. And we found where the hotspot are, and we look at the mix.

One of the things we thought about is what if we step back, and what if we said if you put 1000 megawatts of DG in PG&E's territory, and we look at our hotspots, and we figure out where we should put those, can we go back and then say, okay, biomass group, solar group, low wind group, here is the megawatts that can be installed at the different busses within PG&E's territory. Here's their benefit.

Now, can you take that and work backwards to see what's available in those areas. So if I had given you some penetration levels in Sacramento County, can you go back and filter those by zip code, by counties, by areas, however you need it working with CDF. And then go and say, are there any big subdivisions coming in in those areas. And then begin to look at penetrations. Or can I look at some low wind. In some of the foothills around here is there low wind that I could begin adding those.

And so can I, by one data set, can I go back and then have multiple groups looking at those megawatts and then coming up and look at the aggregation. So instead of looking at them individually, can I get an aggregation of DG to put in there to model.

The other one I want to talk about a little bit here is working with CDF. I put in 105 megawatts of DG, which was solar, residential solar. And we're going to go over those here in a minute.

I kind of talked about this one, but if I was to stand back and have this 1000 megawatts, and I was to look at where it would be at, there's residential PV, commercial PV, landfill gas, wastewater treatment facilities, and other biomass alternatives, that now I can have multiple groups looking at the megawatts, and then looking at the aggregation and then modeling that to look at the benefit on the transmission system.

Because everything is assigned to a location, and XY coordinate, we can do any kind of filtering now that we want to do. We can look at it by utility, by county, by urban area, zip code, ISO congestion zone.

So we'd be able to filter these to be able to look at a wide range of areas and filter these out and looking at penetration levels on the transmission system that could be used for DG.

And so like on the urban area when we're looking at the housing, and if we look at housing development, and then look at the different penetration levels of residential solar, then as we look at our 2005 through 2017 we can develop and look at some trending of penetration levels as we get out over time.

So what I did is I looked at PG&E and I looked at what their hotspot were. And then I limited it to 69 and 115, and I said, well, most of the 69 kV busses are going to be where the distribution of the utility connects, and those are going to be the 69 to 12 kV. And the 115 could be even those where like in San Jose they have the 115 busses that reduce down for serving the customers in the San Jose area off the 115 buss.

And what we did is we backed into it by saying where would I ultimately put 1000 megawatts if I could just go in and pick by the hotspot and the penetration levels, where would I install these.

So what did I end up with? I end up with this map that says I had all these red areas here before, and what my goal is, I start with the red areas and then I try to find out the penetration. And then I back down to look what would happen on the system.

And so strategically, if you were able to locate 1000 megawatts of DG on the system, where would we ultimately want to be putting them on there. And you see we can do a lot of things up in the Sacramento area, and up on into the area, and you still got some areas in the PG&E -- in the San Francisco area we can't really do much. But we do a lot of things down along the Fresno County and Kern County areas.

So now that we have those, and then if I mapped where I put the DG, this would be kind of where the 1000 megawatts would be distributed over. And as you can see how the penetration levels are looking at where the corridors are. They match, as would be expected, where the hotspot are, the major hotspot area. That's where we'd end up concentrating on putting the DGs in.

If I was to break this down a little

farther, and I say, well, what counties did we install the DG in. And then we can look at how many megawatts of the 1028 that we actually installed, where were they located at.

And if you look at the Sacramento County, which ended up being an interesting one, it was only 16 megawatts. You go down and look at San Luis is actually 48. Now whether we could get 48 megawatts in San Luis area is to be seen. It would definitely have to be something else besides solar.

But what we did is we tried to look at these areas and tried to see where would we install them. And you see a lot of counties didn't have any. You'll see 251 megawatts of unmatched. And what those are were busses that we were not able to get XY coordinates. Where those are busses areas that we have in our power flow that we weren't able to tie to a specific area. And although they're in our data set, we haven't been able to tie them into an exact coordinate.

UNIDENTIFIED SPEAKER: Are these just the IOU busses (inaudible)?

MR. DAVIS: These are going to be -- these are strictly the IOU busses. But, for example, for Santa Clara it's going to represent their load at the site of the -- their aggregated load at the PG&E busses that they're being served from. But we did not model, for example, Santa Clara 69 kV system and look at where it would be on there. But this would be representative that you could install some generation at the busses that serve Santa Clara County for example, or the Silicon Valley Power.

DR. TOOKER: Why is King --

MR. DAVIS: That's an interesting one. Why is King County --

DR. TOOKER: No, no. Why is Kern so high?

MR. DAVIS: That's an area that if we go back to the map and we look down on the area, it's an area that it was kind of interesting, we had a large penetration down there on those. And we were kind of surprised that it came out that high on the coordinates.

And we haven't had time to get in to look at that, whether -- we just actually haven't got back into analyzing it any more in detail. And that's one of the things, it kind of stands out, that's an awful lot of megawatts in that area of Kern County that would end up in there.

So I don't have an answer for you right now why it's so high. But it's one that we think should be looked into a little bit more as to the reason. Because I was surprised that that one was 128, but then Sacramento is only 16. So these are some of the things that we need to be looking at.

But what we wanted to try to do is step back and say if we were working backwards, what areas would we concentrate on looking at for distributed generation.

PRESIDING MEMBER GEESMAN: Does the absence of SMUD data understate or under-weight Sacramento?

MR. DAVIS: Yes. Yes, it would. And that's why I think we need a lot of the municipal systems modeled in here so we can get a better handle on where there would be a benefit. If we had more of the 69 and more of the municipals and irrigation districts systems in here we'd get a much better representation.

UNIDENTIFIED SPEAKER: (inaudible).

MR. SIMONS: I was just commenting that we do pick up the substations at the 115 and above for the munis, because that's part of the WECC database. It's when we get down below that voltage that that's where they drop out.

PRESIDING MEMBER GEESMAN: I don't see Riverside on your chart.

MR. DAVIS: Riverside. I did PG&E only.

PRESIDING MEMBER GEESMAN: I'm sorry.

MR. DAVIS: Okay, yes, so we didn't try to do any of the other areas.

But this was just, what we wanted to do was if I could turn this over and have people look at it from different areas, and look at different systems and try to see where we should be putting some -- having people to begin to see what is in those areas, to look at some penetrations.

This was just our phase one to try to get some other information for the DG people.

One of the other things in working with CDF, and these numbers aren't exact, I just worked with them and they gave me some forecasted data. Is I picked Santa Clara County and I picked Sacramento County, and I said, how many new housing might be going in those areas. And it was about, estimate out in I think it was 2010, 2007 I believe it was, was about, potential was about 105 megawatts if we were to look at residential solar.

And here, again, we didn't spend a lot of time going into a lot of detail. We just took a snapshot and tried to look at some megawatts.

And if I assumed 50 percent penetration for new housing in that area, so we were putting about 54 megawatts in each of the counties. And we were looking at where the housing would be and how we would install it.

And here again, I stuck it on the DG -- I stuck these on the 69 and 115 on those two counties.

Now, what happens is -- yeah, I was looking at 2007 -- what happens is by looking at that 1000 megawatts of DG over the entire PG&E area, it has a benefit ratio of 2.44. So putting in 1000 megawatts of DG is equivalent to putting 2440 megawatts on the entire system. Because we're having the bottom up. We're taking it off the distribution, which is offloading the 69 and 115 and the 230. So there's a lot of benefit to the system.

Putting the 105 megawatts, 54 megawatts in each of the two counties, has a benefit of 663 megawatts, or 6.3 to 1 benefit of concentrating solar PV on residential homes in those two counties, has a 6 to 1 benefit in those, because of their loading, and because of the fact we're unloading the system, which is really a high value and really shows that we can model small megawatts of 54 megawatts in a county looking at DG. And be able to feed that up through the transmission system and look at its value.

The reason that one's higher than the 1000 megawatts, of course, is as you're putting 1000 megawatts you're defeating the purpose as you keep adding more and more DG, the benefit decreases. The first megawatt you put in has a high benefit. As you keep adding it, the benefit's lower and lower. So you get to the point where if we kept adding then the ratio would keep going down, as we're getting less benefit as we keep adding the DG or anything else, as we're adding to the system.

So what we wanted to do was, and here again this is just a short little presentation, but what I wanted to try to show is can we model the small increments of distributed generation if we looked at it on an aggregated basis as it comes on to the substations. And can we use those to determine their values going forward.

And can we find locations and come up with a way of finding locations in general, and then working backwards so that now people can say I have these benefits -- or I have these locations, and they provide benefits now. Can I look and see what different technologies would fit into those to make them work.

And until we have some firm numbers on the low side in order to model, we just took a snapshot of these two to show that we can model DG and be able to see their impacts on the transmission system.

So that's really all I was going to cover this afternoon on this one. So it wasn't very long. But, we did look at, as I said, looking at some penetration of residential housing, and looked at if we put those in and what would their benefit be to the transmission system.

So, with that, that's really all I had for this one.

DR. TOOKER: George, I have a followup question regarding biogas and landfill. In evaluating those did you consider their economic lifetimes, and, you know, potential limitations in that respect?

MR. SIMONS: Yeah, in the economic modeling and performance, yes. But we haven't put in, we've been working with CDF on the biomass. The spatial positioning of that in the GIS, and then working it into the electricity analysis, we haven't completed that yet. So you don't see that here.

I think, you know, what I've seen to date, though, from the results is that you're going to get a certain amount of electricity system benefit primarily at the ends of the distribution lines in rural areas.

Sometimes in urban areas where you have, for example, you might see some biomass benefit in areas where they've got a distribution line that's got some potential growth problems as you go out into the '5 and beyond year timeframe. And then you happen to have a certain number of biomass resources located in that urban area, because, in fact, there's a biomass disposal issue.

But generally, I think what we're going to end up seeing is that the primary driver, because of the higher capital and LCOE costs of biomass, you're going to see primarily that they're going to have societal benefits.

My gut feeling is that you're going to see wildfire reduction greatly exceeding the electricity system benefit from biomass.

DR. TOOKER: So would you see the same thing for landfill gas, where you had a certain projected lifetime? That it might fill an economic niche for a certain net period of time in an urban area?

MR. SIMONS: Yeah. And landfill gas is going to be less expensive than direct combustion biomass. So it's going to be that much easier.

Whereas with wildfire reduction that's going to be located far from the urban center. The landfill gas type facilities, the large ones have already been built out, so the ones that we expect to see build out in the future are going to be less than 2 megawatts. And you're going to see them -- for example, I think Sacramento might be very seriously considering looking at landfill gas projects for building out their RPS, because, in fact, there are a couple of good sites within the Sacramento County area.

Do we have any questions? And, again, we can have questions and comments about the DG and renewable DG analysis this afternoon, but I think we're also open to answering any questions about this morning's presentations, especially linked to the DG presentation.

UNIDENTIFIED SPEAKER: (inaudible).

MR. SIMONS: Yeah, the presentations we'll put up on the Commission's website. And then, again, the background information, we'll go ahead and put on a CD. We'll indicate when we post the website, or post the presentations on the website, we'll also give a contact name and phone number so that -- and the email address, so people can contact us and let us know that they'd like a CD.

MS. THOMAS: I'm Chifong Thomas with PG&E. I have a question on the DG modeling for the load reduction. Do you discount them at all, are those effective megawatts? Because the DG generation is not peaking at the same time as the load. And so you may only not have the load reduction that you want, and they may be different at different substations.

MR. DAVIS: Yeah, the way we handled the 1000 megawatts is we modeled that as the peak that occurred at the summer peak temperature that we modeled it in load flow.

Now that isn't to say what's connected as far as the 1000 megawatts. It just says if 1000 megawatts of DG was installed across the PG&E territory, for example, but we didn't correlate that back to connected megawatts that it would take to create that.

We just said if I had 1000 megawatts that was actually available to flow on the transmission grid at the time of summer peak. And because we were looking at it could be a composite of solar, landfill gas, which could be baseloaded; the solar could be really peaking; and it could be a combination of different ones.

So what we were saying is it's just 1000 megawatts that is flowing on the transmission system, but we did not try to say what was associated with connected.

MS. THOMAS: Okay, so the effective megawatts, rather than the installed megawatts?

MR. DAVIS: That's correct, it's effective.

MS. THOMAS: Okay. All right, thank you.

MR. SIMONS: And I think Hank Zaininger did look specifically at a light load case just for that very reason.

MS. THOMAS: Yes, that's another suggestion I would think that it would be a good idea to look at light load cases, because for PV would be okay because you probably won't have any PV at light load cases, anyway. However, the digester gas and everything else may have an impact on the system.

MR. PRICE: Yeah, one of the reasons why our team and our approach decided to go to the hourly model was so that we could look at exactly what we expected in terms of the dispatch of the PV, dispatch of other resources. And compare that to the actual hourly interval load data at the municipal utilities.

So we tried to really line up, you know, rather than just doing the one-hour, we tried to do the whole year to get to that coincidence issue.

PRESIDING MEMBER GEESMAN: We've got aggregated load data for utility service territories. Do we have reliable load data for some disaggregated portion of utility service territory?

MR. PRICE: It really depends on the

utility, but for example, the City of Palo Alto, in our model, we actually have the interval load data on every feeder within Palo Alto.

And some meters are winter peaking, and some are summer peaking. So, if you're to do a screening analysis like we were doing with PV, say, you wouldn't get any capacity benefit at all on those winter peaking feeders that peak after dark.

And so when you find the best spot, none of the PV shows up in those parts of your system. They all show up on the commercial business loop that has peaks that are more coincident with the output of the PV.

PRESIDING MEMBER GEESMAN: And would you think the large investor-owned utilities have similarly disaggregated load data?

MR. PRICE: I think it depends on, and maybe the person from PG&E could comment, in my experience there is typically interval data available by substation and by substation bank. But perhaps not feeder.

PRESIDING MEMBER GEESMAN: It just strikes me that in terms of trying to craft an intelligent solar initiative, and we hear some very big numbers in Sacramento recently, million solar homes, half of all new residential construction. If the state is going to end up paying for, I don't know, half of the cost or a third of the cost or a quarter of the cost, it would probably behoove us to try and target those installations as carefully as we can.

And I think that that will invariably require a very close hand-in-glove working relationship with each of the resident utilities in those service territories.

MR. PRICE: Yeah, I agree with you. I think feeders that have peaks coincident make the most sense. I think also areas that are closest to their capacity, you know, a bottleneck, where there's some value for capacity, have a higher value, as well. Not just coincidence, but am I about to have to build a new transformer.

PRESIDING MEMBER GEESMAN: Right.

MR. PRICE: And maybe --

MR. DAVIS: On the residential solar one of the things we're doing in working with the Commission and CDF, is actually CDF has been doing a lot of work on trying to map out exactly where these new subdivisions are kind of going in by looking at the housing, and trying to figure out exactly where these are going to be going in. What their megawatts might be, the size of the homes. And doing a lot on their surface areas, and looking at those.

And then we've been working with them on trying to map that back down to a buss. And to look at those.

Now, one of the things that's going to happen is a lot of these are going to be in new transmission -- distribution systems that aren't even built yet, and --

PRESIDING MEMBER GEESMAN: Right.

MR. DAVIS: And so then we got a little harder work to do on those, because we're trying to project out to 2010 and '17. And there are subdivisions, but there's not any distribution or any subtransmission there connected to them yet.

But that's one of the things we're working with them, meeting with them, is to try to get the maps like we had done for geothermal and wind, and actually plotting those. And we have some maps, and now we're trying to fine tune those into what is an urban area and what is a subdivision development area.

And then what penetration level should
we use. If we're doing 50 percent, we're not
going to get 50 percent maybe by 2005; maybe it's
10 percent. And then 20 percent. And we're
trying to do a trend and working with George in
his area, and CDF to try to come up with some
penetration levels. And then look at how we would
put those in and model them.

DR. TOOKER: Ron, in working with CDF,
are they also looking at the commercial,
industrial development -- planned development?

MR. DAVIS: Yes. We're doing
residential solar first. And then once we have
some numbers on those, then we're looking at
commercial solar penetration levels. And then
we'll be looking at where those are going to be
and where they're forecast, kind of be in
according to the growth. And then coming up with
some megawatts and doing the same thing for
commercial.

And then maybe looking at some
aggregation of the two together.

DR. TOOKER: So does that commercial
include office space --

MR. DAVIS: I'm looking at George

because he's --

DR. TOOKER: Okay.

MR. SIMONS: Yeah, it'll look at typical, what are defined as typical commercial applications, commercial buildings.

In addition, I was going to mention when Commissioner Geesman asked the question about load profiles, is that we also, under community choice aggregation, are getting some load profiles for up to 10 or 11 communities. And so that information can be brought into play here to see.

In fact, one of the things that we're finding out is that you get a fairly decent perspective on renewables being a high growth profile when you begin getting a lot of commercial type applications in a community versus just residential.

MR. TUTT: Hey, George, is there an attempt to identify the monetary value of your average megawatt contingency overload results? And whether you have a benefit of 2 or 6, what does it mean in terms of dollars? Do you know?

MR. VISNESKY: The answer to your question very simply is that we have looked at the difficulty of doing what you're asking. We understand the importance. And we, working with the power world, people have explored four or five reasonable ways to do it of the probably 25 possible ways to do it.

It takes a different level of analysis than we have been able to do, because what you now are asking the analytical process to do is find the intersection of that value that we said is a relative metric, which is the aggregated megawatt overload, and the system security number to which it is connected on a dynamic basis.

And not to make it too complicated, but very simply, when Kollin was speaking this morning of looking forward and how much you would have to add to improve by some increment the reliability of a system that we picked as constant in 2003 or that is the target, you're now looking at assigning to each one of the points at which you would inject generation a decremental value or incremental value in the case of looking at improved system security, a dollar per megawatt value of that injection.

And in order to do that correctly you've got to look at the aggregate benefit of reducing loading on the system, which could be completely different unless you actually track specifically where those megawatt overloads occur.

So, it's a monumentally more difficult problem. It's absolutely important to think about doing that. The difficulty is figuring out an efficient practical way to do that.

But we're thinking about it, and we've actually -- we think we have a way to get a good proxy for that. Nobody's funded that yet, but, you know, thinking's always free.

Did I answer your question?

MR. TUTT: Yes, I believe you did. A followup, maybe, in the meantime we have the results in terms of ratios. And as policy makers what do we do with those results?

MR. VISNESKY: We actually anticipated that question, almost to the word.

(Laughter.)

MR. VISNESKY: My suggestion is that the policy makers use that metric with some reservation. The reservation being have you determined in your own mind that the circumstances, and let's just pick 2003 as an example, that the circumstances that the 2003 case represents are, in fact, number one, a correct representation of the risk versus benefit that has already been determined to be, let's say at least defendable, if not optimal.

And second, what are the public policy benefits of incrementally improving system security, given that possibly very large issues associated with supplying the internal requirements of a state such as California, would require the support of a very very -- of the large interconnected system in terms of it making an improvement in, for instance, transmission development that may not necessarily be able to be tied to specific benefits associated with jurisdictional ratepayers' benefits.

The typical problem that policy makers get in state commissions is how do I approve a transmission project that may have benefits not only to the people in the state, but benefits across the integrated utilities in the state, and in particular in this case, across state lines, and charge the appropriate amount or allow the California jurisdictional or utility jurisdictional ratepayers to be charged the appropriate amount for the benefit they get from that.

And on the other hand, the other side of that argument is how do I -- do I expect to get any volunteers from outside the state or outside a particular utility's jurisdiction to pony up the bucks to help fund this, even though their ratepayers may not be, in fact, getting dollar-for-dollar benefit for it, but the entire integrated system or network is.

That's the caution I would have. You've got to decide that, how to do that first before you can get very deep in parsing the value of this particular tool for that kind of analysis.

And I know I didn't give you any really good ideas. I just told you what you already knew.

MR. TUTT: It's a hard question.

MR. VISNESKY: Yeah.

MR. DAVIS: Just to expand on that, I think one of the things that has to be done in looking at what we do with this information is are there any additional sites that we should be adding into it? Are there sites that we missed?

Second is, if these are interested areas that you want to look into developing, then we've got to look at the timelines to build these things, and to put them into timelines as to how we would be building them, one to five years, four to nine, what is going to be required.

I think one of the other parts is really important is a lot of these are going to require extensive transmission. And so how do we do the policy associated with siting and approving transmission and transmission routes. And then how do we tie that all together so that conventional renewables and transmission development, as far as the siting and permitting, how do these tie together.

And lastly, I think we need to have the utilities involved in saying we did this by picking some sites and doing some simulations. But are these the areas that you would really tie to; are there areas that they would want to look for options and alternatives.

And then fine tune the costs in order to get you better cost numbers. Remember, we used generic cost numbers, but as has been brought up by PG&E, we need to really be looking at a little more fine tuning on the costs so we come up with a priority list.

MR. SIMONS: I've got to add my two

cents. I think the biggest value of this thing may be the fact that what we've developed is a methodology that allows a common language to be used. If anything, it might accelerate the discussions among project developers and utilities about, okay, so where do we see the need for things. You know, how can we begin to rank different projects.

And I think that, in itself, is probably very worthwhile. Again, because it might accelerate moving along the RPS pathway.

Any other questions or comments?

MR. OLSEN: Dave Olsen from CEERT. Just a followup question on the benefit ratio again, just to help me understand.

Ron, your example of adding 105 megawatts of DG in the two counties and benefit ratio of 6.6. Why did you stop at 105 megawatts? Would adding 200 megawatts create a benefit ratio of 4 that is still obviously beneficial? But how did you make that determination?

MR. DAVIS: Okay, what we did on the 105 megawatts, in working with CDF we kind of took a snapshot, because we're still developing the residential solar data and we're not ready to put it into the model yet to present it.

But I sat with them and I looked at the penetration level that would be practical out around the 2007, as far as new housing. If there were new subdivisions going in, how many megawatts would be potential as a growth potential of these new homes in those two counties.

And then we just took 50 percent of that and said what if only half of those by 2007 had solar on their roofs. And so that's how we arrived at it.

As we move out in time and get more detail and more data, as I was saying before, we can start to look at penetrations over a period of time, because we're looking at -- we need to go past 2007.

But right now we're still working on the data, so that was just an example to say if I looked at a gross, and I took a percentage of that gross as a technical potential, and then looked at it. Can I analyze it and see its benefit to the system.

MR. OLSEN: But in light of what you said about the declining value of incremental additions above a certain point, how do you determine where's the optimum point? What's the optimum benefit ratio?

MR. DAVIS: Well, what we're going to be doing is, let's say it works out to be, I'll just pick a big number, 500 megawatts in Sacramento County.

Well, what we're now going to do is start to run a series and then say we installed 100 megawatts at a time, or 200 megawatts at a time to find out. Or maybe we run the whole 500 and we see what the number is and then we drop down to 400, say, of penetration.

And then compare the contingency overload. Now we can look at how much can really be going until you begin to have less and less of a benefit.

So if we have 500 has a, say a .9 benefit or a .8 benefit, but if we were to drop down and install 300 megawatts of solar, it might be a two to one benefit.

So, by having those over time and looking at the penetrations, now you can develop a curve to say how much do I really want to look at to make the maximum benefit that I would put in for residential solar.

And then stacking commercial solar on top of that, now you can develop a trend line to say how much do I really want to go after as far as those homes. And so I don't have any real substantial return.

MR. SIMONS: I want to comment, Dave, that that was a static picture in time, it was out to 2007. If you had taken that out to 2017 you might get a different answer to that. Just simply again because what we're seeing is, you know, with the bulk transmission system right now, we see a short-term need for additional capacity.

We're not seeing that at the distribution level, because in fact the IOUs have built out the distribution system. As we go out past the horizon you'd see a similar situation developing.

And so I also would see that as we begin looking at the mix of bulk and DG, then you come up with some sort of an optimal mix within specific areas of the state, and also an optimal mix within the entire grid.

Any other questions or comments?

MR. TUTT: I have a question about the renewable DG assessment methodology. One of the factors or inputs there was avoided costs of generation. And I was wondering if there was any time variation to those avoided costs.

MR. SIMONS: Snuller, -- I think both Hank and Snuller looked at that.

MR. PRICE: Yes. I guess the short answer to your question is yes. What we tried to do with ours is look at, from the municipal utilities' perspective, what they thought they would save on the market.

And to evaluate that all four utilities said well, we should really look at the onpeak definition in the wholesale market, which is our 6-by-16 hour block. So we have a value of energy there. And then we have offpeak.

So, we didn't do an hourly market curve or anything like that. We just tried to mirror the value on the wholesale market as best we could.

MR. ZAININGER: I think your question was the value of generation?

MR. TUTT: Yes, time variation to the value of avoided generation.

MR. ZAININGER: Oh, okay. Well, in our study we didn't look at avoided generation. We were deferring just the distribution facility deferral. So that wasn't included in our study.

MR. SIMONS: Any comments by the Commissioners, questions?

PRESIDING MEMBER GEESMAN: I guess, again, if I wanted to design an intelligent solar program, I'm not certain that a 6-by-16 comparison is the way I'd go about doing it.

I think I'd want a much more narrowly focused on the hours of expected avoided generation. And base my cost comparison on those hours.

MR. TUTT: I agree.

PRESIDING MEMBER GEESMAN: Well, let's hope we do design an intelligent solar program.

COMMISSIONER PFANNENSTIEL: I'd just like to say that I think that the -- I'm sorry that I had to step out for a few minutes -- but I think that the information here, and the work that underlay this, is going to help us design, I think, an intelligent solar system.

I was quite taken by the site specific, location specific work when you're looking at the costs avoided, distribution costs, the transmission costs as well as the generation costs avoided, how much they vary by the specific site. And I think that that's going to play heavily into what we do in the future.

Thank you.

MR. SIMONS: Thank you, Commissioners. I guess next steps, we will get out to folks certainly the information from today's meeting. Also the schedule for the upcoming meetings. I mentioned the cost of integration meetings, the study group, renewable transmission study group meetings.

And also, I think we would like to get feedback, any additional feedback, as people have looked at these materials can provide to us.

I would anticipate that the next workshop that we'd have would be again in late October.

PRESIDING MEMBER GEESMAN: Well, I want to thank you, George, and everybody else that made it through the day. This has been an extraordinarily information-rich day. And I think we can make very good use of it.

This is a long process, and I'd encourage you to stick with it throughout. Because there is a lot for all of us to learn.

Again, thank you. We'll be adjourned.

(Whereupon, at 3:58 p.m., the Joint Committees Workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Joint Committees Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 24th day of September, 2004.